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ON THE COVER

Transocean's Sedco 704 semisubmersible was moored and being downmanned in Cromarty Firth, Invergordon, Scotland, when Mark Johnson captured this image. After a rig move, crew members took an elevator down the inside of the leg and then climbed through a small hole onto the pontoon before getting a ride to shore.

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Online Exclusive

Standardization was a hot topic at the Underwater Technology Conference (UTC) in Bergen, Norway; Elaine Maslin reports.

People

Watson leaves BSEE

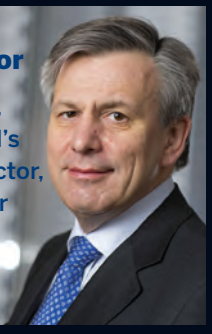
US Bureau of Safety and Environmental Enforcement Director James A. Watson will join ABS next month.

What's trending

Olympus TLP begins journey

Global demand for ultra-deepwater drilling units remains high with new contracts attracting high day rates, according to Fred. Olsen Energy.

Shell picks Voser successor



Ben van Beurden, Royal Dutch Shell's downstream director, is to replace Peter Voser as CEO, starting January 1, 2014.

Expert Access

HMPE rope technology enables deeper and safer operations

Tuesday, August 20, 2013 11:00AM CST

The offshore oil and gas industry continues moving into deeper waters, creating challenges in operations that would be common place in shallow-water projects. New synthetic materials have overcome the limitations of steel-wire rope and make good economic sense for many deepwater applications.

Join Justin Gilmore of Samson Rope Technologies to discuss and answer questions on rope use in the offshore industry and how new materials are enabling the industry's reach into deeper water.

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Voices

Globetrotting. OE sought to uncover which new offshore regions are being targeted as potential new markets. Here's what our think tank had to say:

"Geographically, what offshore region will emerge next as a new market?"

Chariot Oil & Gas is an exploration company with a specific focus on the Atlantic margins - an area within which it views to be of prime geographic importance for new market oil and gas exploration. It has recently acquired licenses in the Barreirinhas basin offshore Brazil, which lies conjugate to the salt basin of Ghana and Cote D'Ivoire, adding to its portfolio on assets offshore Namibia, Mauritania, and Morocco. Chariot believes this acreage to be within highly prospective, underexplored basins with the opportunity for the discovery of large accumulations of hydrocarbons.

Larry Bottomley, CEO, Chariot Oil and Gas

Southeast Asia is definitely a growth target for EV. Countries such a Vietnam and Indonesia are developing fast both in their wider economies and their oil and gas businesses. Myanmar will almost certainly be next on the list. It is becoming much easier to do business in these countries and the potential is significant. EV's downhole camera services are well suited to these markets and we have already done our first jobs in Vietnam and Indonesia. With the lifting of sanctions hopefully Myanmar will be next for us.

Francis Neill, CEO, EV Offshore Ltd.

It's often not that we are targeting a new market, but that we are supplying markets our customers are targeting. At present those markets are West Africa, Asia and Australia. True to say, however, that we remain busy globally, in order to satisfy the demands for oil and gas exploration and production.

Nigel Haworth, Sandvik Global Sales & Marketing Manager, Oil & Gas.

Mexico is one of the largest oil producers in the world. Over recent years, production from shallow offshore fields has declined, however efforts have now been focused on deepwater operations, which come with its own inherent risks and challenges. The oil and gas industry in the region has been very committed to strengthening safety through operational and technological improvements for existing and future operations. Crew transfer offshore is one of the most critical considerations as operators look to maintain efficiency in ongoing projects, while putting in place systems which can effectively support the region's ambitious growth targets.

Grant Wintle, Business Development Americas, Reflex Marine Inc.

The countries to come in offshore are: Brazil, Russia, and Ghana. Brazil's Petrobras is continuing its huge long-term investment program in order to grow production output and commercialize the sub-salt discoveries. Russia is one of the world's largest gas reserves and is sure to be a long-term player. For years, West Africa has been a major oil and gas market, with traditional primary focus on Angola and Nigeria, but there are promising growth opportunities in Ghana.

Magnus Miemois, Vice President, Solutions, Wärtsilä Ship Power

Go to OEDIGITAL.COM and give us your opinion on this month's topic!

Colloquy

Nina Rach

Sylvia Earle receives Hubbard Medal

American oceanographer Dr. Sylvia A. Earle recently received the Hubbard Medal, the National Geographic Society's highest honor, recognizing "leadership in exploration, science, environmental stewardship and education." Earle was honored for her outstanding achievements in marine exploration and conservation in June 2013. Film director and explorer James Cameron and Harvard Professor Dr. E.O. Wilson were also recognized and received Hubbard Medals.

Hubbard history

The Hubbard Medal was named for Gardiner Greene Hubbard, the principal founder and first president of the National Geographic Society. It was first awarded in 1906, to Robert E. Peary, for his polar Arctic expedition. His companion, navigator Matthew Henson, was awarded the medal posthumously in 2000.

Dr. Earle is only the fourth woman to be honored in 107 years; preceded by Anne Morrow Lindbergh (1934); Mary Leakey (1962); and Dr. Jane Goodall (1995).

"Her Deepness"

Sylvia Earle has been at the forefront of deep ocean research for 40 years. She was among the first scientists to use SCUBA diving for research, and has spent more than 7,000 hours under water. Earle holds the women's world record for a solo submersible dive (3,300ft, 1986). She's led more than 50 undersea expeditions, including the first team of women aquanauts in the Tektite Project in 1970. The Tektite habitat was an underwater lab that served as the home to divers during the Tektite programs in Great Lameshur Bay, Saint John, U.S. Virgin Islands.

In 1979, Earle descended to the ocean floor in a submarine off Oahu, with an open-ocean JIM suit (atmospheric diving suit) and walked on the seabed 1,250ft below the surface, setting a human depth record.

In 1982, Earle and husband Graham Hawkes founded Deep Ocean Engineering to design, operate, support, and consult on piloted and robotic subsea systems, culminating in the *Deep Rover* research submarine.

In 1990, she was appointed chief scientist at the U.S. National Oceanic and Atmospheric Administration, and led expeditions to the Persian Gulf in 1991 to determine environmental damage following Iraq's destruction of Kuwaiti oil wells.

In 1992, she founded Deep Ocean Exploration and Research to further advance marine engineering.

Earle has been a National Geographic Society Explorer in Residence since 1998, and holds the Rosemary and Roger Enrico Chair for Ocean Exploration.

The New Yorker and New York Times dubbed Earle "Her Deepness," the Library of Congress calls her a "Living Legend," and Time Magazine, in 1998, named her as the first "Hero for the Planet."

Earle earned a BS at Florida State University (1955) and an MS (1956) and PhD (1966) from Duke University. She held various positions at the California Academy of Sciences, the University of California, Berkeley, and Harvard University.

Mission Blue

Earle's Hubbard Medal is the latest in a long train of accolades and recognitions, including the 2011 Royal Geographical Society Gold Medal, and 22 honorary degrees.

In 2009, Dr. Earle won the TED Prize, awarded annually to "an exceptional individual who receives US$1,000,000 and the TED community's resources and expertise to spark global change. The Prize begins with a big wish—a wish to inspire thinkers and doers across the globe."

Dr. Earle's plan was to "Bring knowledge of our oceans to a wide audience and galvanize support for marine protected areas," using all means, including films, expeditions, the web, new submarines, to help create a global network of marine protected areas.

In April 2010, TED hosted the five-day Mission Blue conference, to draw public attention to ocean protection, on Lindblad's *National Geographic Endeavor* in the Galapagos Islands. Over $17 million was committed to seven ocean conservation initiatives, and MissionBlue.org was launched: an ocean community hub.

Mission Blue is a global initiative that includes more than 100 ocean conservation groups, coordinated by the Sylvia Earle Alliance (SEA), based in California. OE

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ThoughtStream

Marvin Odum

Mexico's moment

Mexico is among the ten largest oil producers in the world. This country has made important structural changes to improve economic performance and strengthen its resilience to external shocks. It is a strong partner to the United States and to Canada.

Three key ingredients for any country's success are: investment, innovation and imagination.

Investment is the obvious one.

Shell invests more than $30 billion every year to meet the growing demand for energy.

The energy industry globally will spend untold trillions over the next four decades to find, develop and produce ever more challenging sources of energy – from traditional oil and gas, to shale gas, to liquids from shales, to advanced biofuels, hydrogen, wind and solar.

Mexico is jostling with countries around the world for a share of that capital. In this hemisphere, it faces fierce competition for capital with Brazil, Colombia, Uruguay, French Guiana, Argentina and others.

Of course, Mexico already has some competitive advantages through free-trade agreements, strategic location, competitive exchange rate, labor costs, and quality manufacturing.

But its advantage will only increase as it attracts more investment with stable and attractive fiscal and regulatory frameworks.

A recent World Bank study suggests Mexico needs the equivalent of five or six additional Pemexes over the next 10 to 15 years to leverage its potential deepwater resources.

The study says investment in deepwater delivers 1.6 times its value in terms of expansion of the supply base, labor development, and supporting services. For onshore investments – including unconventional, complex, capital intensive basins – the factor is around 1.4.

Analysis we've commissioned suggests attracting more capital into the energy sector could increase Mexico's economic growth rate by as much as 5 or 6 percentage points.

And beyond economic growth, we have seen–in countries ranging from Norway to Malaysia–what else happens when countries earn investment in the energy sector: technology booms, an increase in specialized, high-paying jobs, transfer of knowledge into and across the economy, higher industrial safety standards, new levels of transparency, and trust in government.

The potential benefits for Mexico could extend even further, fueling Mexico's continuing progress in the fight against poverty and inequality, its desire to protect its environment, its potential to become a regional manufacturing powerhouse.

But return on investment will go only so far without innovation.

The race is on to create new techniques to find, produce and commercialize more–and more difficult–sources of energy: energy locked in shale, in sand, under ice, in ultra-deep waters.

But it's just as important to look at innovation in how companies, governments and societies work together.

As a global company, with partnerships in almost every corner of the world, Shell has the ability – I'd even say the obligation – to link imaginative ideas across boundaries–intellectual and political–as well as geographic boundaries.

I can see a Mexico that attracts international investment with a sophisticated domestic industry, a network of international partnerships, a talented, skilled and highly-developed workforce, and a commitment to a sustainable and efficient energy system.

It's not hard, with a little imagination, to see a few broad actions, that all of us can take, to get us firmly on the road toward a more sustainable energy system. For example, we could take advantage of the world's 250-year supply of natural gas resources to reduce coal consumption.

Natural gas should play a major role in fostering a cleaner and more sustainable energy system. It's clean, it's abundant, and it can be deployed for everything from electrical power to home use to transport. There is so much of it now available in North America that this continent could become a net exporter of energy in just a few decades.

Marvin Odum *became Director of the Upstream Americas business for Royal Dutch Shell plc in 2009 and continues as President of Shell Oil Co. He earned a BS in mechanical engineering from the University of Texas at Austin and an MBA from the University of Houston.*

[excerpted from Odum's address to Mexican Petroleum Congress, 7 June 2013, Cancun]

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Global Briefs

A Eni and Rosneft gather Barents seismic

Eni and Rosneft began seismic operations in the ice-free portion of the Russian Barents Sea. A 9950km 2D seismic survey is planned over the Fedynsky and Central Barents license areas.

Eni and Rosneft formed joint venture companies to operate each of the Russian offshore projects, with Rosneft holding a 66.67% stake and Eni holding the remaining 33.33%.The project is part of the wider cooperation between Eni and Rosneft sanctioned under the Strategic Cooperation Agreement entered into by the parties on 25 April 2012.

B Statoil strikes oil

Statoil announced a light, high-quality oil discovery at its Harpoon prospect (EL 1112) in the Flemish Pass basin, off Newfoundland, Canada. The semisubmersible *West Aquarius* drilled the well in about 1100m of water. Harpoon is located 500km northeast of St. John's and about 10 km southeast of Statoil's Mizzen discovery. The Mizzen discovery is estimated to hold between 100-200MMbo. Statoil plans to return to the Flemish Pass later this year to drill at Bay du Nord, southwest of Harpoon. Statoil operates Harpoon with a 65% interest, while Husky Energy holds 35%.

C Discovery increases Appomattox reserves

Shell made a 100million-bbl, deepwater oil discovery in the Gulf of Mexico, adding to the potential of its Appomattox find. The Vicksburg A discovery is nearby Appomattox, which contains about 500million bbl of potentially recoverable resources.

Vicksburg A is a separate accumulation from both Appomattox and the 2007 Vicksburg B discovery. It is 120km (74.5mi.) offshore in De Soto Canyon block 393 in 2269m (7446 ft) of water. The well was drilled to a total depth of 8042m (26,385 ft) and encountered more than 152m of net oil pay.

D BHP signs four PSCs

BHP Billiton the signed four production sharing contracts (PSC) with Trinidad and Tobago for four deepwater blocks that the company won in December. The PSCs cover Trinidad and Tobago Deep Atlantic Area (TTDAA) blocks 5, 6, 28 and 29. TTDAA acreage (40,000sq km) lies to east of producing oil and gas fields in 600-3500m water depths.

Each block has an initial phased exploration period of up to nine years and provides an automatic extension to 30 years for a commercial discovery. Economic activity is expected to generate a minimum investment of about US$565 million for the mandatory exploration phases and US$459 million during optional exploration phases. In the first phases, 5330sq km of 3D seismic will be gathered and at least six deepwater exploration wells will be drilled.

E Petrobras sets production records

Petrobras set a new pre-salt production record in May 2013 with output of 322,100bo/d, an 11,000bo/d increase from its previous record of 311,500bo/d set the prior month. The company also achieved record output in Espírito Santo, with a monthly average figure of 322,700bo/d, surpassing the previous record set in December 2011.

During May, the production for all Petrobras Brazil fields averaged 1.892 million bo/d. Non-liquefied natural gas output from Petrobras' fields in Brazil was 59.7MMcu m/d.

F Woodside's first Irish acreage

Woodside Petroleum acquired its first offshore exploration acreage in northwest Europe with its agreement to farm-in to three license options in the Atlantic Porcupine Basin. Woodside will become operator of all three licensing options, subject to regulatory approval.

From Petrel Resources, the company will acquire 85% in licensing option 11/6, containing blocks 45/6, 45/11 and 45/16, and licensing option 11/4, containing blocks 35/23, 35/24 and 35/25. It is also acquiring 90% in licensing option 11/3, containing blocks 35/25(e), 35/30, 36/21, 36/26, 44/5(p) and 45/1, from Bluestack Energy.

G Cairn to appraise Spanish Point discovery

Cairn Energy will to drill an appraisal well on its Spanish Point discovery off western Ireland using the semi *Blackford Dolphin* in 2Q 2014. Spanish Point is a gas and condensate field in license FEL 2/04 developed by Phillips in 1981. It is at the northern end of the Porcupine Basin in about 400m of water.

Cairn was recently approved as operator after completing a farm-in, in which it gained 38% working interest in licences FEL 2/04 and FEL 4/08. Partners in the licenses include Chrysaor (26%), Providence Resources (32%) and SOSINA Exploration (4%).

H Hellenic Petroleum wins Patraikos block

A consortium of three companies has made a successful bid for an exploration concession on the Patraikos block, off western Greece. Hellenic Petroleum (operator), Petroceltic International, and Edison International, will each hold a one-third working interest in the concession.

The Patraikos block is in the Gulf of Patra and covers 1892sq km in 100-300m water depth. Hellenic Petroleum expects the new concession to be formally awarded to the companies in late 2013. The three-year initial exploration period includes a work program of 2D and 3D seismic data acquisition.

I CNR International signs PSC

CNR International signed a production sharing contract (PSC) for Block CI-12 off Cote d'Ivoire (Ivory Coast), with a 60% working interest. CNR International will operate the block, located west of the company's Espoir and Baobab fields, in 250-300m water depths. The block contains two undeveloped discoveries, drilled during the 1980s, and potential Turonian fan channels that were not penetrated by previous wells.

J Eco seismic planned

Eco Oil & Gas (Atlantic) is planning seismic surveys after receiving a one-year extension on two exploration licenses off Namibia. The extension to the Guy (2111B & 2211A) and Sharon (2213A & 2213B) licenses, both in the Walvis Basin, will allow more time to complete 1000sq km of 3D seismic on each of the licenses in 2015. Eco will then drill an exploration well in 2016. Eco will also gather out 500sq km of 3D seismic on the Cooper license (2012A) later this year, together with partners AziNam and NAMCOR.

K BG finds Tanzania gas

BG Group has made a gas discovery in the Ngisi-1 well in Block 4 off Tanzania. The well, drilled by the *Deepsea Metro 1* drillship, appraised the Chewa gas field resulting in an upgrade in estimated recoverable resources in the block. Recoverable resources across the Chewa-Pweza-Ngisi hub are now estimated at 4.5Tcf, up from 3.7Tcf. BG is operator of Block 4 with 60%, while partner Ophir Energy holds 40%.

Nick Cooper, CEO of Ophir, said: "The successful Ngisi drilling results provide critical mass for the aggregation and development of the gas discoveries in Block 4. These (reserves) will be piped ashore and combined with the Block 1 resources for Tanzania's LNG development."

L Kashagan production to start

North Caspian Operating Company (NCOC) began work to start production of Kashagan field in the Caspian Sea. The first phase will see production from eight wells on an artificial island complex. Wells, pipelines, and the Bolashak Onshore Processing facility have been completed. Offshore production and treatment facilities on the artificial island complex are in the final stages of commissioning.

"During 2013/14, production will be progressively ramped up to the design capacity from 180,000b/d in the first stage, and up to 370,000b/d in the second stage," says NCOC.

Kashagan field is 75km southeast of the city of Atyrau. The reservoir lies about 4,200m deep, beneath 3–5m water, and extends over an area of about 75km by 45km. Kashagan and neighbouring fields in the Caspian Sea hold 35billion bbls of estimated reserves in place.

M Transocean sets drilling record

Transocean Ltd. announced that the ultra-deepwater drillship *Dhirubhai Deepwater KG1* set a new world record for the deepest water depth by an offshore drilling rig. The drillship spudded a well in 10,411ft (3,174m) water depth, while drilling off India's east coast for ONGC. This surpasses Transocean's prior record of 10,385ft (3,165m) set by the same drillship in February 2013.

N Rosneft's seismic program

Rosneft began seismic acquisition over license blocks Lisyansky, Kashevarovsky, and Magadan-1 in the Sea of Okhotsk off eastern Russia. The company is gathering 2D seismic along with a gravity and magnetic survey, using the *Academik Fersman* seismic vessel. The program will cover 10,000km: 5300km

Steel cut for Ichthys FPSO

The Inpex-operated Ichthys LNG Project cut first steel in Okpo, Korea for the hull of its floating production, storage and offloading (FPSO) vessel. The vessel will be used for condensate dewatering, stabilisation, storage and export. When completed, the FPSO will be permanently moored in the Browse Basin, off Western Australia. Condensate will be offloaded periodically to crude oil tankers and shipped directly to market.

The FPSO is being built by Daewoo Shipbuilding & Marine Engineering (DSME). Speaking at the steel-cutting ceremony at the DSME shipyard, Inpex Ichthys LNG project director offshore Claude Cahuzac said the event marked a major milestone.

"Starting fabrication on the FPSO hull means that work is now underway on all major offshore facilities – this includes the central processing facility, subsea structures and the gas export pipeline," Cahuzac said. "It marks the culmination of years of engineering work and close collaboration with our contractors."

on the Lisyansky licensed block, 2000km on the Kashevarovsky block and 2700km on Magadan-1. Rosneft operates the blocks in partnership with Statoil.

Environmental and fishery research will be carried out by Environmental Co. of Sakhalin. The Khmitevskaya-2 well drilled in Magadan-1 will be studied for environmental affects.

PetroBoard explores block 28/03

China National Offshore Oil Corp. (CNOOC) signed a PSC with PetroBroad Copower Ltd. for block 28/03 in the Pearl River Mouth Basin. Block 28/03 covers 68sq km with 95m water depth. PetroBroad will acquire 3D seismic surveys and drill exploration wells during the exploration period, and will bear all costs. CNOOC has the right to participate in up to 51% working interest in any commercial discoveries

Salamander multi-well program

Salamander Energy plc

began its six-well exploration program in block G4/50, Gulf of Thailand. The first well, G4/50-4, was spudded at the end of June. It is being drilled on the Rayong prospect in the northeast section of the block in the central Kra sub-basin. The well is drilling to about 2000m TVD subsea using the *Atwood Mako* jackup and is targeting Miocene sandstones and Permian Ratburi carbonates with 20-50MMbo of recoverable resource.

Block G4/50 covers over 5,800 sq km and contains five sub-basins, four of which have a proven oil source. Salamander has a 100% operated interest in block G4/50.

Gumusut-Kakap gets FPS

Sabah Shell Petroleum Co. Ltd. received a semisubmersible floating production system (FPS) for Malaysia's Gumusut-Kakap deepwater field offshore Sabah. The FPS was handed over to Sabah Shell in early June and is installed in about 1200m water depth. Once commissioned, it will be the largest offshore operating facility in Asia.

The FPS has the capacity to process up to 150,000 boe/d and will initially service seven subsea manifolds. The field's full development system includes 19 subsea wells, linked to the FPS. An oil export pipeline will transport crude oil from the FPS to the Sabah Oil and Gas Terminal in Kimanis, Sabah. Sabah Shell operates the field with Petronas, ConocoPhilips, Sabah Ltd., and Murphy Sabah Oil Co. Ltd. as partners.

CGG begins Carnarvon Basin 3D

CGGVeritas Services SA began a marine 3D seismic survey over Karoon Gas Australia's WA-482-P permit area in the Northern Carnarvon Basin. The survey will cover about 2386sq km and will define leads and prospects first identified on existing 2D and 3D seismic data. CGG is using the *Geo Caspian* to gather the data and preliminary results are expected near the end of 2013.

The WA-482-P permit is in the first year of a three-year initial term and the seismic evaluation work will prepare the company for a drilling decision required before the start of the third-year work commitment. Karoon is completing the final equity transfer process. At completion, and subject to farm-in obligations, Karoon will hold a 100% equity interest in WA-482-P.

Montara first oil

PTTEP Australasia achieved first oil from the Montara field in the Timor Sea off Western Australia. The *Montara Venture* FPSO started production at the H2 well in early June. The company expects to ramp production to 21,000bo/d with first off-take of oil from the FPSO occurring by August. Development of a fourth production well, H5, is scheduled for 2H 2013.

Contract Briefs

Technip contract for Snøhvit

Technip was awarded a lump sum contract for pipelay and subsea installations for the Snøhvit CO_2 Solution project by Statoil. Snøhvit field is located about 140km northwest of Hammerfest, Norway. The project will establish an additional well at a new CO_2 injection template, as well as prepare for gas production from existing templates. The contract covers fabrication and installation of flowlines, including two 5km, 13% chrome, stainless steel production flowlines and a 5km CO_2 injection flowline; installation and tie-ins of spools, jumpers and umbilicals; and installation of a new combined production and injection template and manifold. The flowlines will be welded at Technip's spoolbase in Orkanger, Norway, while installation will be performed by the *Apache II* in the first half of 2015. Installation of the associated umbilicals, template, manifold, spools and other subsea equipment will be performed by other Technip vessels.

FMC tree order

FMC Technologies, Inc. received an order from Petrobras for subsea trees for its pre-salt fields off Brazil. The award is estimated at US$500 million and represents the call-off of the remaining value of the $1.5 billion agreement announced in March of 2012.

The order includes 49 subsea trees, tooling, and associated subsea controls. The trees are scheduled to be installed in multiple pre-salt fields for both production and injection wells. The equipment will be designed and manufactured at FMC Technologies' facilities in Brazil.

Subsea 7 wins three PLSV contracts

Subsea 7 will build and operate three, flexible, pipe-lay support vessels (PLSV) for Petrobras under three five-year contracts worth about US$1.6 billion. The contracts include project management, engineering and installation of flowlines, umbilicals, and equipment supplied by Petrobras.

The three new PLSVs will be based on similar design to the *Seven Waves*, and will be built in Holland at the IHC Merwede shipyard. The vessels are scheduled to be delivered in 3Q 2016, 4Q 2016 and 2Q 2017.

The PLSVs are designed to operate in 3000m water depths, and will be equipped with a pipe-lay system for installing flexible flowlines and umbilicals, including a lay system tower with 550-tonne, top-tension capability, twin underdeck baskets, for storing up to 4000tonne of flexible flowlines, and two state of the art ROVs. Total cost of the three vessels, inventories, commissioning, and mobilization to Brazil, is about US$950 million.

Wood Group wins contract extension

ConocoPhillips (UK) extended one of its longest running projects in the North Sea under a US$60 million (£40 million) one-year contract extension with Wood Group PSN. WGPSN will continue to provide operations and maintenance services, and facilities modifications services to ConocoPhillip's 50 manned and unmanned offshore assets in the southern and central North Sea and the onshore Theddlethrope gas terminal in Lincolnshire.

Saipem EPIC for Egina

Saipem has been awarded the contract for the Nigerian subsea development of the

Egina field, in a 1700m water depth. It is worth approximately $3 billion. Fabrication will be performed almost entirely in Nigeria and most in the Saipem Rumoulumeni Yard in Port Harcourt.

Saipem signed an EPIC contract with Total Upstream Nigeria Ltd for the subsea development of the Egina field, located in the Oil Mining Lease 130, about 100km south of Port Harcourt. The scope of work includes engineering, procurement, fabrication, installation, and pre-commissioning of 52km of oil production and water injection flow lines, 12 flexible jumpers, 20km of gas export pipelines, 80km of umbilicals, and mooring and offloading systems. Marine activities will be performed throughout 2016, continuing to the second quarter of 2017.

Egina subsea order for FMC

FMC Technologies, Inc. received an order from Total Upstream Nigeria Ltd. for subsea equipment for the Egina field. It has an estimated value of $1.2 billion. The supply scope includes subsea trees and wellheads, manifolds, installation tooling, flowline connection systems, and associated control systems. The equipment is scheduled for delivery beginning in 2015.

Exxon's Julia work contracts

ExxonMobil chose Oceaneering International Inc. to supply production control umbilicals for its US$4 billion Julia development in the Gulf of Mexico. The order is for a 14mi.-long (22.5 km), electro-hydraulic, steel-tube umbilical. The umbilical will supply hydraulic control fluids, chemicals, and electrical power signals to operate and monitor the subsea wells and manifold used in the field. The water depth is about 7200ft. Manufacturing will be performed at Oceaneering's facility in Panama City, Florida, with delivery scheduled for early 2015.

McDermott announced it has also won a Julia contract from Exxon for engineering, procurement and construction of jumpers, four suction piles, subsea pump, pump transformer, and subsea distribution unit/umbilical termination assembly, as well as the transportation and installation of the equipment. The company will also carry out testing of the tie-back system and mechanical completion.

Bumi Armada wins pipeline contract

Bumi Armada Caspian LLC signed a supplementary agreement worth RM567.6 million (US$178.5 million) with OOO LUKOIL-Nizhnevolzhskneft for EPIC (engineering, procurement, installation and pre-commissioning) work in the Caspian Sea's Russian sector.

The workscope includes the engineering and procurement of line pipes with related equipment, and the installation and precommissioning of six infield/inter-field lines, for a total length of about 40km. Installation work will be done with the derrick pipelay barge, *Armada Installer*, and will be completed in 2015.

DCP for Malampaya

Shell Philippines Exploration B.V. awarded Royal Boskalis Westminster N.V. a contract to install a Depletion Compression Platform (DCP) for the Malampaya Project off Palawan Island, in The Philippines. The contract is worth about US$60 million and will be completed in 2014.

ENGINEERING

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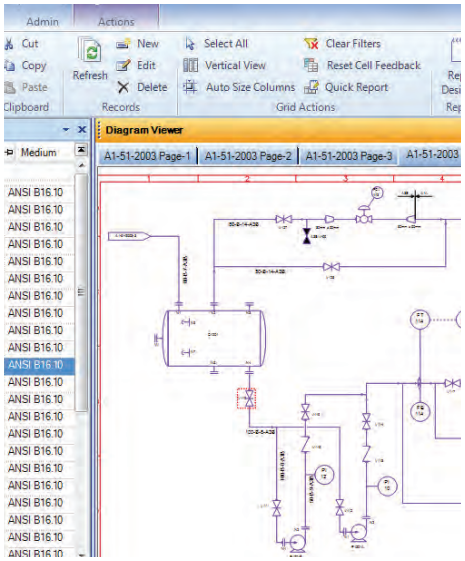

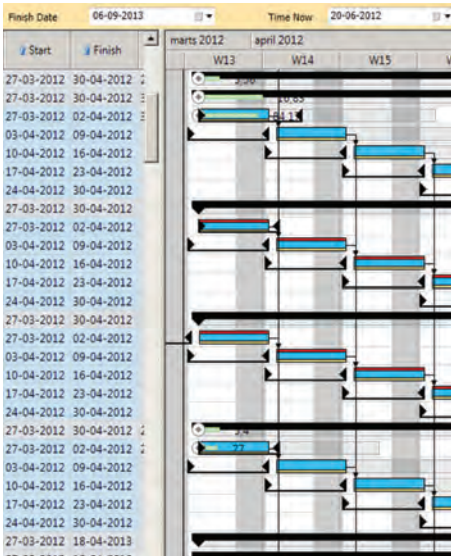

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Analysis

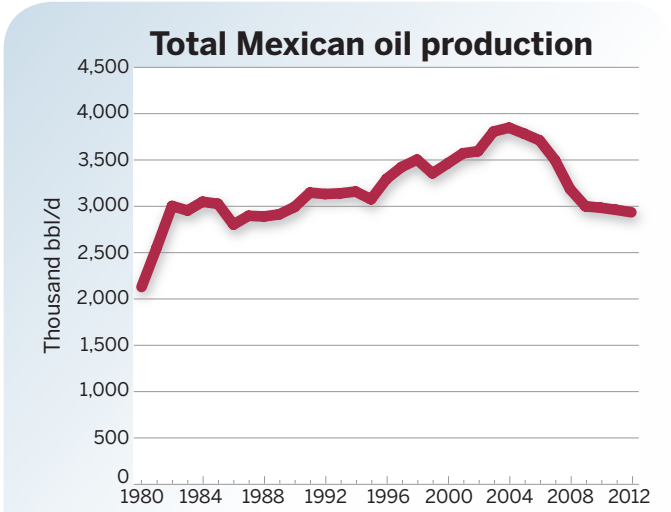
Energy reform in Mexico: Is it time?

By Jose Valera and Gabriel Salinas

President Enrique Peña Nieto recently announced that he will send a "transformational" energy reform bill to Mexico's Congress in the coming months in an effort to attract the private capital and expertise required to develop Mexico's deepwater and shale deposits, and reverse the country's declining energy production.

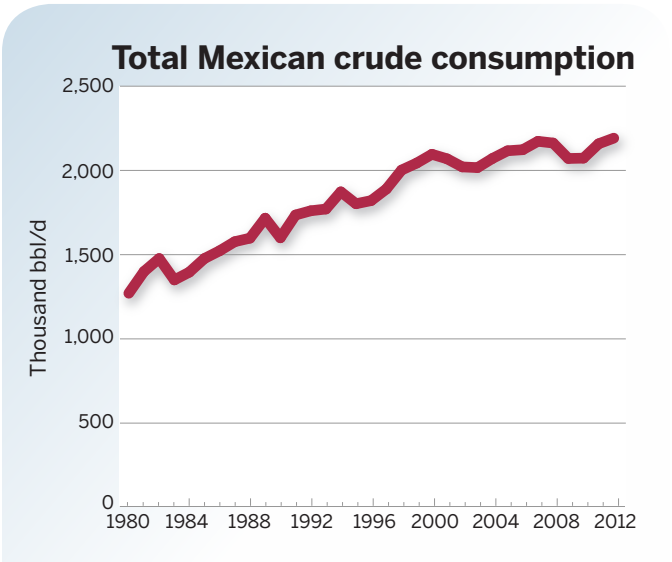
Although companies have been providing oil-related services to Pemex, Mexico's state-owned national oil company, for several decades, private investment in Mexico's upstream sector has been absent since the country's oil industry was nationalized in 1938. The absence of such investment is due to constitutional limits on private involvement in the exploration and production of hydrocarbon resources. Such restrictions, together with Mexico's massive Cantarell oil field discovery in the late 1970s, explain the very limited investment and attention to exploration activities in Mexico.

In recent years, Mexico has experienced significant



In 2012, Mexico produced an average of 2.94MMb/d of total oil liquids, down from a peak of 3.85MMb/d in 2004, a 23.6% decline in production in one decade.
Source: U.S. Energy Information Administration.

Analysis

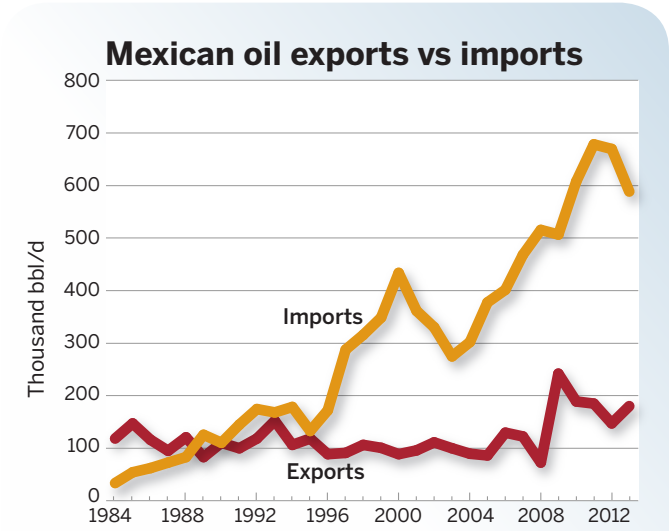


Mexico's total energy consumption in 2010 relied mostly on oil (56%), followed by natural gas (29%).
Source: U.S. Energy Information Administration.

declines in oil reserves, production and exports. At the same time, with the growth of the Mexican population, the country's consumption of refined oil products and natural gas has increased significantly, causing Mexico to rely heavily on imports from the United States and other countries. Although Mexico has considerable natural gas resources, its production has been relatively limited. Since crude oil sales represent one of Mexico's main sources of income, equaling nearly a third of the national budget, Pemex has never focused on natural gas development. Furthermore, partly because of the private investment restrictions, Mexico's refining capacity is capped, with only six refineries and a total refining capacity of 1.54 million bbl/d, all operated by Pemex. As a result of these factors, Mexico, despite its status as one of the world's largest crude oil exporters, is a net importer of refined petroleum products and an importer of natural gas. If these trends are not reversed, the country is expected to become a net importer of crude oil by 2020.

Mexico does not lack for resources. As of January 1, 2011, Mexico had 10.4 billion bbl of proven oil reserves and an estimated 46 billion bbl in 3P (proven, probable and possible) reserves, mainly located in the deep waters of the Gulf of Mexico. According to a recent US Energy Information Administration report, Mexico also has the world's sixth-largest technically recoverable shale gas resources (see reference).

In an effort to uncap this potential and halt the decline in production and exports, Mexico's previous presidential administration proposed comprehensive energy reform in 2008. However, that reform proposal was significantly diluted before being approved by Mexico's Congress. The final 2008 energy reform established the legal framework for upstream service contracts with private companies for the development of mature fields that allowed for some



Mexico is expected is to become a net importer of crude oil by 2020, if import/export trends are not reversed.
Source: U.S. Energy Information Administration.
* Pemex Monthly Petroleum Statistics

limited performance-related bonus payments. While the 2008 reforms were a step in the right direction, they fell short of the expectations of many hoping to reverse the country's declining production trend by bringing in private capital, technology and expertise. Notably, the profit-sharing and reserve booking restrictions were left unchanged by the reform. It is widely acknowledged that such restrictions would need to be lifted in order to attract the capital and expertise needed to develop Mexico's deepwater and shale gas resources, which hold most of Mexico's prospective reserves.

Legal framework

Mexico's constitution, like the constitution of the majority of countries in the world, provides that hydrocarbons in the subsoil belong to the state. Article 27 provides that, when it comes to hydrocarbons, "no concessions or contracts shall be granted, …and the Nation shall carry out the exploitation of those substances, under the terms set forth in the respective Regulating Law."

The constitution also stipulates that hydrocarbons and basic petrochemicals are "strategic areas" for which the public sector shall have responsibility "in an exclusive manner." However, the constitution does not establish that only Pemex shall develop Mexico's hydrocarbons. In fact, the constitution does not contain the words "Pemex" or "Petróleos Mexicanos." Moreover, the constitution only limits the "exploitation" of oil and derived products and not other downstream activities.

The Regulatory Law of Article 27 (*Ley Reglamentaria del Artículo 27 Constitucional en el Ramo del Petróleo*) goes beyond the terms of the constitution in at least two ways. First, it establishes that all of the following, and not only the "exploitation" of oil, are activities that are reserved to the

Quick stats

OE's at-a-glance guide to offshore hydrocarbon reserves and key offshore infrastructure globally is updated monthly using data from leading energy analysts Infield Systems (www.infield.com).

New discoveries announced

Depth range	2010	2011	2012	2013
Shallow (<500m)	92	102	72	16
Deep (500-1500m)	28	25	23	6
Ultradeep (>1500m)	29	20	34	10
Total	**149**	**147**	**129**	**32**

Note: Operators do not announce discovery dates at the time of discovery, so totals for previous years continue to change.

Reserves in the Golden Triangle

by water depth 2013-17

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	22	1,721.75	980.00
Deep	16	3,257.00	2,255.00
Ultradeep	40	12,428.45	17,340.00
United States			
Shallow	21	96.45	1,253.50
Deep	23	1378.71	1624.87
Ultradeep	24	2,995.00	3,340.00
West Africa			
Shallow	151	3,453.60	18,237.81
Deep	47	5,574.00	6,420.00
Ultradeep	16	2,540.00	3,000.00
Total	**360**	**33,444.96**	**54,451.18**
(last month)	(363)	(35,039.96)	(55,331.18)

Greenfield reserves

2013-17

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	1,315	77,066.36	832,926.99
(last month)	(1,334)	(78,915.96)	(837,641.99)
Deep	165	13,879.58	83,871.57
(last month)	(168)	(14,304.58)	(84,711.57)
Ultradeep	99	18,392.45	67,197.00
(last month)	(99)	(18,322.45)	(65,907.00)
Total	**1,579**	**109,338.39**	**983,995.56**

Pipelines

(operational and 2013 onwards)

	(km)	(last month)
<8in		
Operational/ installed	41,793	(41,744)
Planned/ possible	23,645	(23,272)
	65,438	(65,017)
8-16in		
Operational/ installed	77,457	(77,255)
Planned/ possible	47,149	(47,029)
	124,606	(124,284)
>16in		
Operational/ installed	88,414	(87,825)
Planned/ possible	48,333	(48,217)
	136,747	(136,042)

Production systems worldwide

(operational and 2013 onwards)

Floaters		(last month)
Operational	277	(275)
Under development	48	(48)
Planned/possible	313	(316)
	638	(639)
Fixed platforms		
Operational	9,655	(9,637)
Under development	145	(144)
Planned/possible	1,467	(1,475)
	11,267	(11,256)
Subsea wells		
Operational	4,416	(4,411)
Under development	411	(393)
Planned/possible	6,007	(5,981)
	10,834	(10,765)

Global offshore reserves (mmboe) onstream by water depth

	2011	2012	2013	2014	2015	2016	2017
Shallow	10,421.19	6,132.60	65,316.14	31,247.39	38,700.72	35,037.35	54,172.29
(last month)	(10,421.19)	(6,130.72)	(65,204.92)	(32,401.99)	(42,849.50)	(31,609.64)	(54,536.19)
Deep	1,312.21	1,768.96	3,528.61	5,788.99	4,320.26	5,353.47	9,675.04
(last month)	(1,312.21)	(2,533.96)	(3,616.76)	(5,845.40)	(4,351.94)	(5,177.22)	(10,996.57)
Ultradeep	199.94	737.15	3,090.44	3,075.06	1,789.91	6,060.93	16,231.98
(last month)	(199.94)	(797.15)	(3,090.44)	(3,075.06)	(1,789.91)	(6,108.56)	(16,114.35)
Total	**11,933.34**	**8,638.71**	**71,935.19**	**40,111.44**	**44,810.90**	**46,451.76**	**80,079.31**

11 July 2013

Analysis

nation: exploration, exploitation, refining, transportation, storage, distribution, and first-hand sales of crude oil and refined products. The law creates the concept of a "petroleum industry," defines the industry as including all such activities, and provides that petroleum industry activities are strategic within the meaning of the constitution. Thus, pursuant to the Regulatory Law, private companies are prohibited from participating in exploration, production, transportation, refining, and sale of crude oil and its products; all exploration and production of natural gas; and the extraction, transportation, storage, distribution, and sale of natural gas liquids as feedstock.

Second, the Regulatory Law provides that the nation shall carry out petroleum industry activities only through Pemex, thus sanctioning the monopoly of Pemex over all these activities. Only Pemex, and not private companies, may receive "assignations" of contract areas.

The Regulatory Law also restricts the consideration payable by Pemex under service contracts for the exploration and production of hydrocarbons, prohibiting payments in kind or otherwise sharing in production, and prohibiting any form of sharing or allocation of sales proceeds or profits. Thus, a private company may not own production, share in the proceeds from the sale thereof, or share in the profits from the project. The 2008 energy reform did not change the fact that only Pemex may carry out petroleum industry activities and that only Pemex may realize their upside.

The upstream service contracts resulting from the 2008 statutory reforms are, essentially, (1) for enhanced recovery operations on marginal oil fields, and (2) for natural gas development in areas previously explored by Pemex. So far, compensation under these contracts is in the form of cost recovery and is fixed, per-unit of production cash compensation (which is adjustable for inflation). The total compensation payable to the contractor in any one year may not exceed Pemex's net cash flow from the same project during that year.

Energy reform

Mexico's current administration is expected to propose an energy reform bill as early as September 2013. According to statements from the administration, the bill could call for amending the constitution and legislation to allow private companies to participate in profit-sharing arrangements and joint ventures with Pemex, and would lift the prohibition on booking hydrocarbon reserves. The bill is likely to focus on, and may be limited to, the development of Mexico's deepwater and shale gas deposits, where most of the country's untapped reserves are believed to lie and where Mexico lacks the expertise required for extraction. Other onshore and shallow-water reserves, where Pemex has expertise and lower costs, are likely to remain under the current regime.

Such a bill is likely to face some opposition, but President Peña Nieto's administration appears confident that the

so-called Pact for Mexico (*Pacto por Mexico*) among the country's three major political parties—the PRI, PAN, and PRD—will ensure passage of an energy bill by year's end.

Only six months into his term, President Peña Nieto has managed to push through two major constitutional reforms in the telecommunications and education sectors, has proposed a comprehensive financial reform, and is expected soon to propose both energy and fiscal reforms, all of which were agreed upon in the Pact for Mexico.

Passage of a constitutional amendment in Mexico requires a two-thirds majority in both houses of Congress and an affirmative vote of a majority of the state legislatures. The ruling party, the PRI, holds slightly less than 50% of the seats in both houses of Congress, and would need the cooperation of one of the two other major political parties—the PAN and the PRD—to pass a constitutional amendment. The PAN is expected to support the energy reform bill. Thus, even without the support of the PRD, which has traditionally opposed energy reform, the PRI and the PAN would have enough votes to pass the necessary changes to the constitution. Politically, however, and pursuant to the Pact for Mexico, a consensus between the three parties would be required.

Congress is prepared to debate the forthcoming proposal. Congressional leaders of Mexico's main political parties have agreed to hold two special sessions during the summer to tackle outstanding initiatives so that they can focus on the energy and fiscal reforms in September. OE

Reference:

Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States. US Energy Information Administration. June 2013. Web: http://www.eia.gov/analysis/studies/worldshalegas/pdf/fullreport.pdf.

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Gabriel Salinas *is an associate in Mayer Brown's global energy practice in the Houston office. He focuses on international corporate and energy transactions and projects. He has experience representing companies on cross-border mergers and acquisitions, asset and equity sales, joint ventures, and oil and gas exploration and production projects, with a focus on Latin America.*

Clearing infrastructure– from the Gulf of Mexico to the North Sea

Technology can be transferred from the Gulf of Mexico to new markets such as the North Sea and beyond. Scott Adams, sales manager of Decommissioning Services, and Caroline Grant, Operations Manager, provide insight from Gulfstream Services Inc.

Gulfstream Services Inc. grapples provide advanced decommissioning equipment solutions to the international oil and gas industry.

Infrastructure removal activities using cutting-edge technology in the Gulf of Mexico have been ongoing for the past 10 to 15 years, says Gulfstream Services Inc. (GSI). Fortunately, much of the technology first developed in the Gulf can be transferred to newly emerging markets such as the harsher, deeper environment of the North Sea.

With approximately 150 structures to be removed from the Gulf by yearend 2013, the current market could reach US$1 billion per year of capital spend, according to Scott Adams, sales manager of decommissioning services for Gulfstream, based at headquarters in Houma, Louisiana.

Meanwhile, some 600 offshore oil and gas installations can be found in the North Sea, according to Decom North Sea, an industry forum for the North Sea decommissioning supply chain. The structures, many of which have been producing for the past 40 years, range from modest structures in the southern North Sea to very large concrete and steel structures to the north.

"Many of these will have to be decommissioned during the next few years," says Caroline Grant, operations manager for Gulfstream, based in Aberdeen, Scotland. In fact, under current regulatory requirements, more than 90% of the offshore structures must be completely removed from marine-state sites. The rest, such as the large and heavy steel and concrete installations, could be repurposed as a base for wind farms, wave-power structures or other uses. The workload, including an estimated 10,000km of pipelines, approximately 5,000 wells and accumulated drill cuttings, represents a cost of about $80 billion during the coming 25 years.

Yet, North Sea decommissioning operations can be challenging. "Decommissioning operations in the North Sea typically take longer than those activities in the Gulf of Mexico," Adams says. "That's mainly due to larger structures in deeper water in a harsher environment. Those variables require extensive planning, and typically create a shorter weather-related decommissioning seasoning. This entails the end user to further concentrate their efforts on efficiency."

The North Sea sector technology is ever evolving accounting for weather and harsher environments. In addition, UK legislative issues have prevented foreign-based companies from proactively planning for timely decommissions. "This has caused a portion of our UK work to be reactive," Adams says.

Grant agrees. "Until the legislation is changed, it continues to be a huge issue. Hopefully new regulatory changes, meant to take effect in 2014, will come into fruition."

The UK's Department of Energy and Climate Change's (DECC) rules affect the decommissioning and recovery operations of gas fields, hydrocarbon pipelines and other types of installations.

"We are challenged by that on a daily basis, although our equipment can work in a harsh environment," Grant says. "It is detailed to the type of vessels that can work there, such as dynamic positioning vessels, which are hired by the operators to go in and conduct work. Fortunately, our product lines are not adversely affected by the harsh environment. As a decommissioning service company, we

Shears are used for many decommissioning projects including platform and pipeline removal, slot recovery, chain cutting, wire rope cutting, salvage work and well blow out intervention.

can provide solutions as these technical requirements and feasibilities studies are completed."

North Sea case study

A majority of Gulfstream's work in the North Sea is pipeline-related. Recently, the company put its shear technology to work decommissioning pipelines associated with the North West Hutton platform in the North Sea. The platform was the first large fixed-steel jacket installation to be decommissioned in the region after its field production ceased in 2003.

The steel platform stood at 140m water depth on Block 211/27a of the UK Continental Shelf. A 10-in. diameter pipeline had to be left mostly on site with some sections removed, and a 20-in. pipeline had to be trenched and removed at three crossings, among other tasks in the work scope. The seabed soil was very hard with medium to large boulders in various locations.

During the decommissioning, the operator compared hydraulic shear technology cutting methods to other cold cutting methods such as dual band saws, chop saws, and abrasive water-jet cutting.

The study found that the average actual pipeline cutting time using shear technology was 11 minutes on the 10-in. line, compared to the dual-cut band saw, which took 21 minutes. The chop saw took 49 minutes, while the abrasive water-jet cutting took 1 hour and 22 minutes. Working on the 20-in. line, the shear cut in 8 minutes while the abrasive water jet cut in 1 hour and 2 minutes. The other methods were not attempted.

Operations for the cutting boat-to-boat times for the 10-in. pipeline included equipment deployment and repositioning, dredger setup, dredging, cutting, further repositioning, and hydraulic grapple recovery. The shear technology completed its tasks averaging 1 hour and 30 minutes with a total of 8 cuts. The band-saw method averaged 2 hours and 37 minutes with a total of 10 cuts. The chop saw averaged 2 hours and 59 minutes with a total of 6 cuts. The abrasive water-jet averaged 4 hours and 6 minutes while making 3 cuts.

The same operations conducted on the 20-in. line with the shear technology took 1 hour and 30 minutes with 56 cuts. The abrasive water-jet took 4 hours and 6 minutes with 4 cuts. Other methods were not used.

The operator learned that the intervention made to change the cutting technique used for the concrete coated pipelines was successful because, although the initial methods and tools that were used to make the cuts were effective, they were not time efficient, so consideration of other tools as a contingency at an early stage is important. Other learnings included that operators should ensure that their acquired survey data is recent and accurate, and that accurate soil data is necessary to allow better engineering decisions to be made. An hour in the office can save days offshore.

According to the operator's analyses, GSI's shearing and grappling services typically reduce pipeline decommissioning cutting times by 200% to 300%, providing huge cost savings to its customers. On three separate occasions

Gulfstream Services Inc. provides cost savings to customers with shearing and grappling services to reduce pipeline decommissioning cutting times by 200-300%.

in the North Sea GSI's decommissioning services have been requested to replace the initially chosen cutting contractor and finish the job. Our services resulted inreduced on-location time, equating to a huge cost savings for the client," Adams says.

Since oil and gas shearing technology was introduced in 2005, greater than 7,000 shear cuts and 5,000 subsea debris removal grapple retrievals have been logged worldwide by GSI. This experience has provided many lessons learned along with experienced seasoned technicians.

Cause for innovation

Working and learning how to operate in the Gulf of Mexico during temporary harsh environments, or after the fact, can lead to innovative processes, services and products that can be used in both the Gulf and the North Sea. For example, after the *Deepwater Horizon* drilling rig explosion in the Macondo oil field on April 20, 2010, GSI was required to refocus its efforts on the decommissioning side due to more stringent government regulations. As a result, Gulfstream recently developed a new product line, known as the Spill Mitigation Device.

"This is a flow control device used in the event of a hydraulic hose or umbilical breach," Adams says. "It minimizes the amount of hydraulic fluid, which could be released into the environment. We proactively designed, developed, and are manufacturing this patent-pending device, which will help operators meet new legislation which requires best efforts to minimize hydraulic fluid loss during an accidental hose breach or leak. Our customers are looking at it as a well-designed, proactive and effective new technology."

While actively participating in the decommissioning market both in the Gulf of Mexico and North Sea, GSI is aware of its clients' emergency needs.

Indeed, that capability is timely. The Gulf Coast is experiencing unusually warm weather this summer, which can heat up seawater, strengthen hurricane wind force, and enlarge a storm's circumference. In preparedness, should a weather-related incident occur, Gulfstream has already signed first-right-of-refusal contracts for its shear technology with two major offshore operators. Adequate equipment and personnel are stationed in Louisiana and are prepared for quick response.

"Our priority is to respond to the client's needs in the event a production platform is damaged or toppled," Adams says. "Our current level of assets, personnel are capable of addressing any emergency decommissioning needs in the Gulf of Mexico."

A focus on reducing personnel exposure through equipment development and eliminating chance of environmental damage is at the top of everyone's priority list. Thus the industry is ever changing. It is moving to eliminate hot work. This means that the future of the industry will entail more cold cutting with shears, saws and abrasives, while eliminating torch cutting by divers."

Future opportunities

In the Gulf of Mexico, great portion of the decommissioning industry's work has been done in shallow-and intermediate-depth water on the continental shelf, Adams explains. As the industry expands and deeper water developments mature, those areas will be required to be decommissioned as well.

These deeper water activities will entail tooling powered by alternate sources such as ROV. Deeper water always demands an increase in technology even within the decommissioning sector.

Going forward, Gulfstream sees new opportunities developing in the Caspian Sea as many of the older Soviet installations have reached the end of their life cycle. "In addition to that, a market for decommissioning services in Southeast Asia, based in Kuala Lumpur, is on the rise as well," he says.

Planning for the future with an eye toward new markets and increasingly innovative technologies is a key strategy for Gulfstream Services. To create efficiencies and streamline the processes, Gulfstream continues to invest significant capital in new technology and product-line development. OE

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BSEE: Offshore decommissioning accelerates in Gulf of Mexico

By Nina Rach

The Bureau of Safety and Environmental Enforcement (BSEE) has jurisdiction over decommissioning of "idle iron" wells and structures, pipelines, and the Rigs-to-Reefs program.

According to BSEE, there were about 2,996 production platforms on the US Outer Continental Shelf (OCS), as of March 2013.

About 27% of the existing platforms (813) are non-producing or otherwise fit BSEE's definition of "idle iron," which means there are plentiful opportunities for companies that specialize in removing structures and seabed debris. According to Dean Murphy, DecomWorld, the decommissioning market is valued at US$30-40 billion.

Idle Iron directive

On 15 September 2010, then-Secretary of the Interior Ken Salazar and Bureau of Ocean Energy Management, Regulation and Enforcement Director Michael R. Bromwich announced a new Notice to Lessees (NTL) requiring companies "to set permanent plugs in nearly 3,500 nonproducing wells ... and dismantle about 650 oil and gas production platforms." NTL 2010-G05 went into effect 30 days later, on 15 October, and companies were allowed 120 days to submit plans for decommissioning. Subsequently, 2011 was a record year for decommissioning activity in the Gulf of Mexico.

DecomWorld reported that 2012 was the second largest market for structure removal ($835 million), and the fourth largest year for revenue generated through well abandonment ($737 million). Decommissioning strategy is driven not only by the Idle Iron NTL, but also by the threat of hurricane activity, operator's aversion to risk, and expanded budgets.

Michael J. Saucier, field operations supervisor in BSEE's Gulf of Mexico OCS regional office, noted that some facilities topple during hurricanes, risking pollution, and that it costs significantly more to clean up, plug, and abandon a toppled well. Saucier said that BSEE received 97 idle iron plans, covering:

– 3092 idle wells (96 %) of 3233 total idle wells.
– 1056 expired wells (85 %) of 1246 total expired wells.
– 600 idle platforms (97 %) of 617 total idle platforms.
– 259 expired platforms (89 %) of 292 total expired platforms.

Regulations

Decommissioning activities in US waters are governed by Title 30 (Mineral Resources) of the Code of Federal Regulations (30 CFR) Part 250, Subpart Q and the following subparts:

§250.1700 Definitions

(a) *Decommissioning* means
  (1) Ending oil, gas, or sulphur operations; and
  (2) Returning the lease or pipeline right-of-way to a condition that meets the requirements of regulations of BSEE and other agencies that have jurisdiction over decommissioning activities.

(b) *Obstructions* mean structures, equipment, or objects...or marine growth that, if left in place, would hinder other users of the OCS.

(c) *Facility* means any installation other than a pipeline...that is permanently or temporarily attached to the seabed on the OCS. Facilities include production and pipeline risers, templates, pilings, and any other facility or equipment that constitutes an obstruction such as jumper assemblies, termination skids, umbilicals, anchors, and mooring lines.

§250.1703 What are the general requirements for decommissioning?

When your facilities are no longer useful for operations, you must:

(a) Remove all platforms and other facilities.

§250.1711 When will BSEE order me to permanently plug a well?

BSEE will order you to permanently plug a well if that well:

(a) Poses a hazard to safety or the environment; or

(b) Is not useful for lease operations and is not capable of oil, gas, or sulphur production in paying quantities.

Notice to Lessees (NTL) 2010-G05 defines "No longer useful for operations" which is used in the regulations for:

Wells with no production for 5 years or no plans for future operations; and

Platforms that have toppled or have not been used in past 5 years for operations associated with exploration, development, or production of oil/gas.

NTL requirements:

Idle wells must perform one of the following within 3 years of making the idle iron list:

PA the well in accordance 250.1712 -.1717; or TA the well in accordance 250.1721; or Provide the well with downhole isolation. Within two years of setting downhole plugs, they [operators] must either PA/TA the well.

Idle platforms must be removed as soon as possible, but not longer than five years after it became no longer useful.

Implementation

BSEE is tracking companies' compliance with their submitted idle iron abandonment plans.

Inventory of idle iron at time of NTL issuance (9/15/2010):
• 3233 total idle wells
• 617 total idle platforms.

Current Inventory of idle iron (as of 2/22/2013):
• 2016 total idle wells (including 260 newly idle since NTL)
• 400 total idle platforms (including 62 newly idle since NTL).

Platform removal permits approved since Oct. 15, 2010:
• 770 total platform removal permits approved since the NTL
• Major structure – Platform containing at least 6 completions or contains more than 2 pieces of production equipment.

Well abandonment permits (APMs) approved since Oct. 15, 2010: TA Approved 2388 (51%); PA approved 2324 (49%) = 4712 total TA/PA permits approved since the NTL.

Pipelines

Decommissioning pipelines is governed by 30 CFR §250.1750-250.1754. Pipelines may be decommissioned when they do not constitute a hazard or obstruction...unduly interfere with other users of the OCS, or have adverse environmental effects. Pipelines must be removed if the Regional Supervisor determines that the pipeline is an obstruction.

Table 1: Gulf of Mexico Pipelines

Status	Miles
Active	24,126
Abandoned	12,628
Proposed to be installed	2409
Proposed to be abandoned	2264
Out-of-service	2425

Table 2: Pipeline permits, Jan. 1, 2010-March 19, 2013

Permits for:	Received	Approved
Installation	369	546
Decommissioning	1367	1369
Repairs	638	610

Saucier acknowledged that BSEE will have to increase staff to meet enforcement challenges, and expects that continued development on the OCS will lead to more decommissioning activity.

Note: Some data drawn from presentation by Michael J. Saucier, BSEE Gulf of Mexico OCS Region, at 5th Annual Decommissioning & Abandonment Summit, March 2013, Houston.

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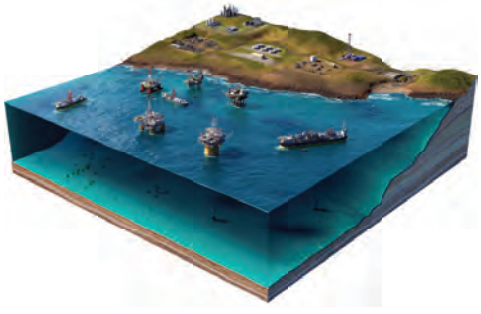

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Supply chain shortfalls on the UK continental shelf

A new report shines a spotlight on the UK's decommissioning supply-chain's future needs.

The latest estimate of future spending on decommissioning in the UK Continental Shelf (UKCS) is approximately £35billion by 2040.

To date, fewer than 60 structures have been either decommissioned or are in the process of being decommissioned.

High oil and gas prices, improved recovery technologies and fiscal uncertainty has seen the deferral of decommissioning projects, making the UK Continental Shelf's decommissioning sector somewhat embryonic.

However, installations will at some point reach the end of their economic lives and with tax relief deeds recently introduced in the UK sector, allowing greater clarity on tax relief for operators when making decommissioning decisions, a maturing of the UK sector is expected by the industry.

Against this backdrop, decommissioning industry forum Decom North Sea (DNS) worked with government agency Scottish Enterprise and consultants Accenture to produce a detailed assessment of the current state of the sector—a first of its kind.

The research, outlined in a report, *Decommissioning in the UKCS*, suggests there is an average gap of 35% between actual and desired capability across the supply chain.

Areas showing a greater deviation between supplier capability and industry-desired capability were found to be well abandonment (see panel), infrastructure removal and continuing liability—ongoing monitoring activities required to ensure a decommissioned field is safe and compliant to regulations.

The Brent field, operated by Shell, has nearly 1000km of more than 30 year old well bore across 142 wells and 240 sidetracks from four platforms. The Brent Delta platform alone had 112 wells and sidetracks, of which all but six have now been abandoned.

Decommissioning in the UKCS extract: focus on well abandonment

There are around 11,500 UKCS exploration, appraisal, suspended and production wells all requiring abandonment (Oil & Gas UK DEAL).

Some wells, of up to 30 years old, have yet to be abandoned and there are often structural integrity issues and other complexities, which can cause timelines to stretch and costs to escalate.

This is reflected in the Oil & Gas UK figures which forecast well abandonment to be the most expensive phase in the decommissioning lifecycle over the next five years, amounting to 44% of total decommissioning spend.

The major risks for well abandonment are poor rig and well condition, poor well access and integrity and the availability of rigs and vessels including LWIVs (light well intervention vessel).

The strengths in the sector were found to include the presence of global players in the region, with knowledge and expertise and a culture of improvement among suppliers. Waste and scale treatment had the highest capability.

Weaknesses include resourcing issues,

Areas with the least deviation were cleaning and decommissioning (the removal of hydrocarbons and hazardous materials from infrastructure) and disconnection and disposal (cutting and separating elements of an asset in preparation for its removal and transfer to shore and options once onshore).

Others areas where capability is likely to be particularly stretched are highlighted as access to engineering staff, drilling rigs for well plugging and abandonment, and vessels, including heavy lift vessels.

"A major cause for concern is the demand on people resources," says Brian Nixon, chief executive of DNS. "The North Sea supply chain is welcoming huge new development projects, such as Clair Ridge and Mariner, as well as major investments in offshore renewables, sustained levels of operational expenditure and opportunities in other countries, such as Norway, which are facing similar pressures.

"Against this backdrop, decommissioning must be regarded as an attractive opportunity if we are going to build the capability, capacity and efficiency required for this major program of activity."

Brian Nixon, chief executive of Decom North Sea.

Nixon suggests better training and transferal of skills and capabilities from other sectors, such as nuclear decommissioning, the military and marine and salvage industries.

He also suggests collaboration across different skills pools, to create catalysts for innovation, and for suppliers to share techniques, processes and learnings.

Encouraging innovation and improving interface management would also help improve operators' confidence in their decommissioning projects, he says.

Among its recommendations, the report suggests bundling different services and forming alliances between niche suppliers could help to share risks and reduce costs, through synergies in areas such as project management and logistics and HSSE management.

DNS represents more than 220 companies and organizations active in the North Sea's oil and gas decommissioning industry.

It has a number of initiatives to support the industry, including a streamlined template for the submission of decommissioning programs.

Its annual conference will be held on 1-3 October—in partnership with Oil & Gas UK—in St Andrews, Scotland. OE

including a struggle to attract personnel to what is seen as an unglamorous sector, and an underestimation of the complexity of work needed. Rig upgrades work was the weakest supply activity.

With many wells having been suspended decades ago, their current condition is often poor, without the operators knowing. In fact, operators have stated recently that one in five wells requiring abandonment is a "train wreck," leading to an approximate doubling of the average forecast time to the average actual time required to abandon a well. The Society of Petroleum Engineers reported recently that about 34% of wells in the UKCS have structural integrity issues.

A lack of regular integrity checks, as well as old and lost documentation, add to the issue, increasing timeframes and costs during abandonment. There are also bottlenecks in available capacity of equipment, such as rigs, vessels, and cranes.

This phase likely presents the greatest test of all the phases of decommissioning to the supply chain, given the size and complexity of the challenges that lie ahead.

However, with strengths in the well servicing market, current capabilities could be transferred and tailored to suit abandonment needs. More knowledge sharing, better integrated planning, and a focus on resourcing will probably be key to the success of the abandonment supply market.

Recommendations include:

A need for earlier planning, and execution, which will reduce complexity and risk, and improve performance and cost containment

Integrated planning—operators to suppliers and suppliers to suppliers—allowing for greater visibility, improved sequencing and better opportunities for collaboration.

A push to broadcast the challenge and complexity of the task ahead, which would stimulate operators to think more about their plans and investment, the government to consider support and regulatory revision, and suppliers to further expand capability

A coordinated drive for increased training and recruitment in the abandonment area, with a focus on transferring skills from similar sectors

Integration with other phases during decommissioning, to allow suppliers and operators to better plan and sequence activities, as well as creating synergies. ■

UKCS Decommissioning—the next five years

It is estimated that the total cost of UKCS decommissioning in the next five years will be about £4.5billion, focusing on 40 platforms and their associated wells, pipelines and subsea structures, across 80 fields.

Latest estimates for the same period show that total decommissioning costs in the more mature Gulf of Mexico will amount to about £3billion—£1.5billion less than in the UKCS.

Decommissioning spend across the UKCS will vary by region, with the Northern North Sea and Central North Sea having considerably higher costs per installation [platform] than the Southern North Sea.

This is due to factors such as heavier structures, deeper water, being further from shore, and more hostile weather conditions. With operators often undertaking their first decommissioning project, different strategies and contracting approaches are likely to emerge, which will also affect costs from one decommissioning project to the next, according the *Decommissioning in the UKCS*.

Costs can also vary across different phases of decommissioning, with the well abandonment phase forecast to account for more than 40% of total costs, while the suspension cold phase (the bridge between an asset being hydrocarbon-free and disconnected and the commencement of removal activities) is forecast at less than 1%. ■

Predicting pore pressure by modeling shale compaction

Figure 1. Geologists, geophysicists, engineers, soil scientists, and clay mineralogists (author on top of hill in cap) study the Niobrara Shale on a 2012 field trip to the Denver Basin, Colorado, USA.

James T. Krushin,
Consulting Geologist

Shales are very fine-grained, clastic rocks that lose porosity through compaction. Sedimentary basins typically contain about 70% shale, Figure 1. Quantifying shale properties helps with predrill geologic and seismic interpretation, basin modeling, and wellbore design. Knowing shale properties can also improve safety and reduce drilling well costs by overcoming wellbore stability issues.

Because shales lose porosity via compaction, they have been used to forecast and quantify pore pressure. Though, only one of the many controls on shale porosity is effective stress. The key to proper shale pore pressure interpretation is isolating the effective stress control on porosity. Overpressure knowledge is important because it affects drilling safety and costs, hydrocarbon column seal integrity, and rock and fluid acoustical properties.

Traditional pore pressure models use shale resistivity, acoustic velocities, and/or exponential porosity loss, which do not properly identify or isolate all the variables and components of compaction. Though, in the defense of practitioners of these techniques, it is only recently with the widespread use of non-water based mud that non-altered shale bulk density measurements are representative of insitu conditions.

Compaction is a reduction in bulk volume or thickness (i.e. porosity loss) in fine-grained sediments, due to continually-deposited material that compresses the underlying sediments. Compaction components include: mechanical, thermal, and chemical changes to the shale. Mechanical changes are associated with increasing effective stress (overburden stress); thermal changes are due to increasing temperature with depth (geothermal gradient), and chemical-changes come from diagenesis (transformation of smectite to illite). A robust compaction-based, pore pressure model must account for all these components, as well as variable shale lithology, to correctly isolate the pore pressure effect on mechanical compaction.

The model outlined here uses

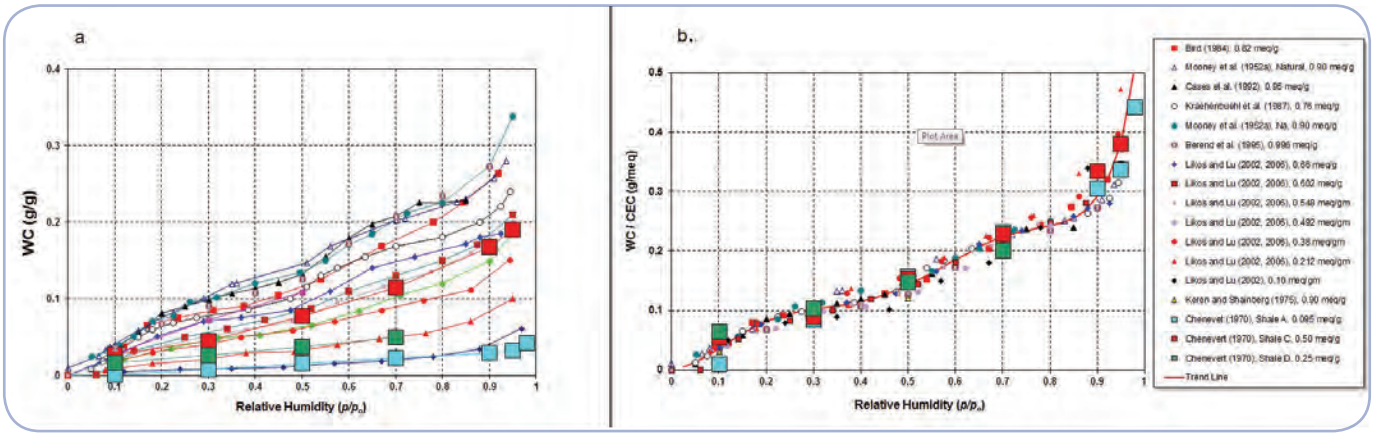

Figure 2. a. Water vapor desorption isotherms replotted from published studies of Na-exchanged pure clays and shales. The larger square symbols are actual shales. b. illustrates how the data collapses to a trend when the water content (WC) is normalized by the CEC. Figure adapted from Krushin (2008).

the cation exchange capacity (CEC, meq/g) of the bulk shale as a surrogate for mineralogy and grain size. CEC is a measurement of the amount of exchangeable charge per unit mass of dry sample and is derived from well logs, similar to a published method. The process involves several steps to link the different elements into the final model. At the "heart" of the compaction model are water desorption isotherms.

Developing the model

The use of water vapor desorption isotherms, a technique historically used to quantify the water associated with pure clays provides a surprisingly rigorous shale compaction model. Water vapor desorption isotherms, derived from published studies of Na-exchanged clays, clay mixtures, and shales properly model the controls on shale porosity. These isotherms are simply a chart of the water content of the sample (g/g) plotted against the relative humidity as it is decreased from 100%, Figure 2a. A general trend arises when the water content is normalized by the CEC, Figures 2a and 2b.

Soil scientists and civil engineers have noted that the compaction of fine-grained soils collapses to a trendline when the water content (or the volume equivalent porosity) is normalized by the CEC or a surrogate such as the liquid limit or total surface area, when plotted against effective overburden stress. Both the liquid limit and total surface area correlate extremely well with CEC.

The relative humidity converts to effective overburden stress via the thermodynamic Kelvin equation:

$$Pe = -C\frac{RT}{V_w} ln^{p}/_{p_o} (1),$$

where, Pe is effective overburden stress (psi), C is a constant (14.7) to convert units, R is the gas constant (0.083liters atm/mole K), T is absolute temperature of the isotherms (297K), Vw is partial molar volume of pure water (0.018 liters/mole), and p/po is the relative humidity.

Figure 2b does not represent a true compaction model because the chart was developed only with data measured at about 75 °F. The geothermal gradient must be incorporated to properly account for thermal compaction. Then the model can be properly applied to temperatures associated with oil and gas drilling. Again, water sorption isotherms prove up to the task.

The sample's sorption isotherm at a higher temperature has less water for a given relative humidity (i. e., effective stress state, Eq.1). The thermal effects on compaction are accounted for by applying the thermodynamic Clausius-Clapeyron equation to the isotherms trendline, Figure 2b. This permits the mechanical compaction component (e. g., pore pressure via effective stress) to be isolated from the thermal and chemical compaction component as

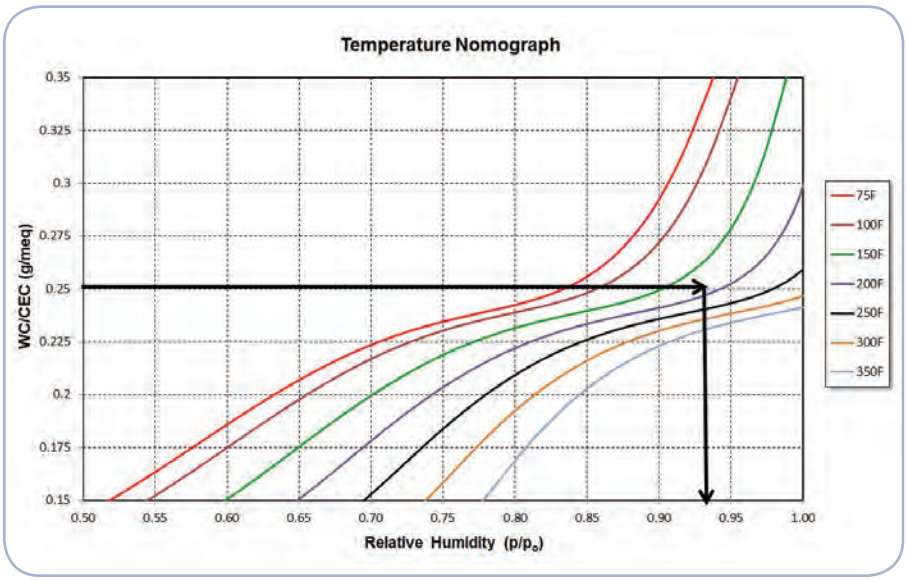

Figure 3. The trendline in Figure 2b is adjusted for increasing temperature (°F). This diagram permits the calculation of effective overburden stress for the shale on a foot-by-foot basis. WC/CEC is obtained from standard well logs. This temperature nomogram shows how effective overburden stress can be determined graphically (black arrows). Figure adapted from Krushin (2008).

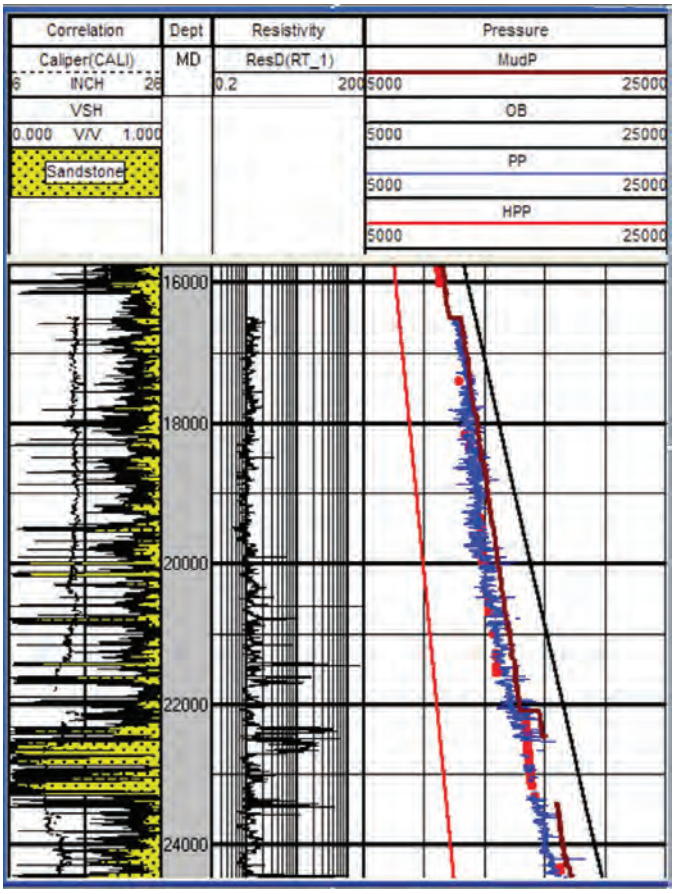

Figure 4. This display applies the model to a deepwater Gulf Coast USA well drilled with oil-based mud. Depth is in ft. Track 1 contains the volume of shale (VSH) and is used simply as a cutoff. Where VSH is greater than 0.5, the model is applied. Track 2 is the deep resistivity. Track 3 shows the hydrostatic pore pressure (HPP), the model derived pore pressure (PP), the equivalent circulating mud pressure (MudP), and the overburden pressure (OB). Red circles are the MDT pressures taken in the sands. All pressures are psi.

well as variable mineralogy. Figure 3 shows graphically how the general trendline is adjusted by temperature.

Applying the model

The pore pressure calculated from the compaction model outlined here is truly porosity based. Because of extremely low permeability in shale, it is impossible to calculated shale pore pressure to directly verify the model. Therefore, the pore pressure derived from this model has to be compared to inferred pore pressure from drilled mud weights deemed correct and measured pressures in adjacent sands with little structural relief.

Inputs to the model are water content normalized by the CEC (WC/CEC), and insitu temperature. The WC is the mass equivalent of porosity. Porosity is calculated from the bulk density curve, using a grain density of 2.73 and a water density of 1 g/cc. In petrophysical lingo, it is considered "total porosity." As previously stated, the CEC is derived from well logs using a modified published technique. The insitu temperature is derived from the geothermal gradient. Figure 3 shows how WC/CEC and temperature results in a graphically derived relative humidity (p/po). This relative humidity, converts to effective stress (Pe) via Eq. 1 and is repeated on a foot by foot basis for the shale in the interpreted well. Pore pressure is then determined by rearranging the effective stress relationship:

$$Pp = OB - Pe \quad (2),$$

where, Pp is model derived pore pressure, OB is total overburden pressure, commonly derived from integration of the density log and Pe is derived from relative humidity (Eq. 1). All units are psi.

There is excellent agreement between the modeled shale pore pressure outlined here with pore pressure inferred from drilled mud weights and pressures measured in interbedded sands illustrated in Figure 4. Since, shale is so abundant and challenging to drill, a robust compaction model will help explorers and drillers by properly modeling seismic, forecasting geologic technical risk, decrease well costs, and improve drilling safety. **OE**

Jim Krushin is a consulting oil and gas geologist with over 30 years experience, working in the US and internationally. He worked for 15 years at Amoco Production Co. in Houston, Texas and Tulsa, Oklahoma in exploration and exploitation. His interests include quantifying reservoirs, seals, pore pressure, and shales. He earned BS and MS degrees in geology from the University of Pittsburgh and is a graduate of Amoco's Petrophysics Training program, where he researched shale petrophysical properties.

FURTHER READING

- "A True Shale Compaction Model with Pore Pressure Prediction," OTC 23954-MS, 2013.
- "A Compaction-Based Pore Pressure Model for Shales," Gulf Coast Association of Geological Societies Transactions, v. 58, p. 575-586, 2008.
- "Quantifying Shale Porosity-A Thermodynamically Based, Predictive Model which includes the Effects of Mechanical Compaction, Temperature, Mineralogy, and Chemical Diagenesis," Gulf Coast Association of Geological Societies Transactions, v. 55, p. 401-414, 2005.

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Protecting subsea hydraulic systems

Determining accumulator best suited for an application depends on the environment in which it will operate, reliability, and maintenance cost.

By Aaron Glafenhein and Tim Leister

Accumulators are energy storage devices that have a variety of applications. Most notably, they can be used to store potential energy, accommodate fluid expansion or provide damping for pressure transients. Accumulators are typically positioned on the high-pressure side of a system, whereas similar devices on the low-pressure side are referred to as reservoirs. For this discussion, the term accumulator refers to both device types.

There are many different types of accumulators, each with its advantages and disadvantages, to consider when designing hydraulic systems for subsea applications, including thermal and volume compensation, energy storage, and water-hammer damping. Among the key criteria in the selection process are cost, service life, maintenance, performance, and reliability. Reliability is particularly important, since the wrong choice can cost millions of dollars in additional maintenance and operating costs.

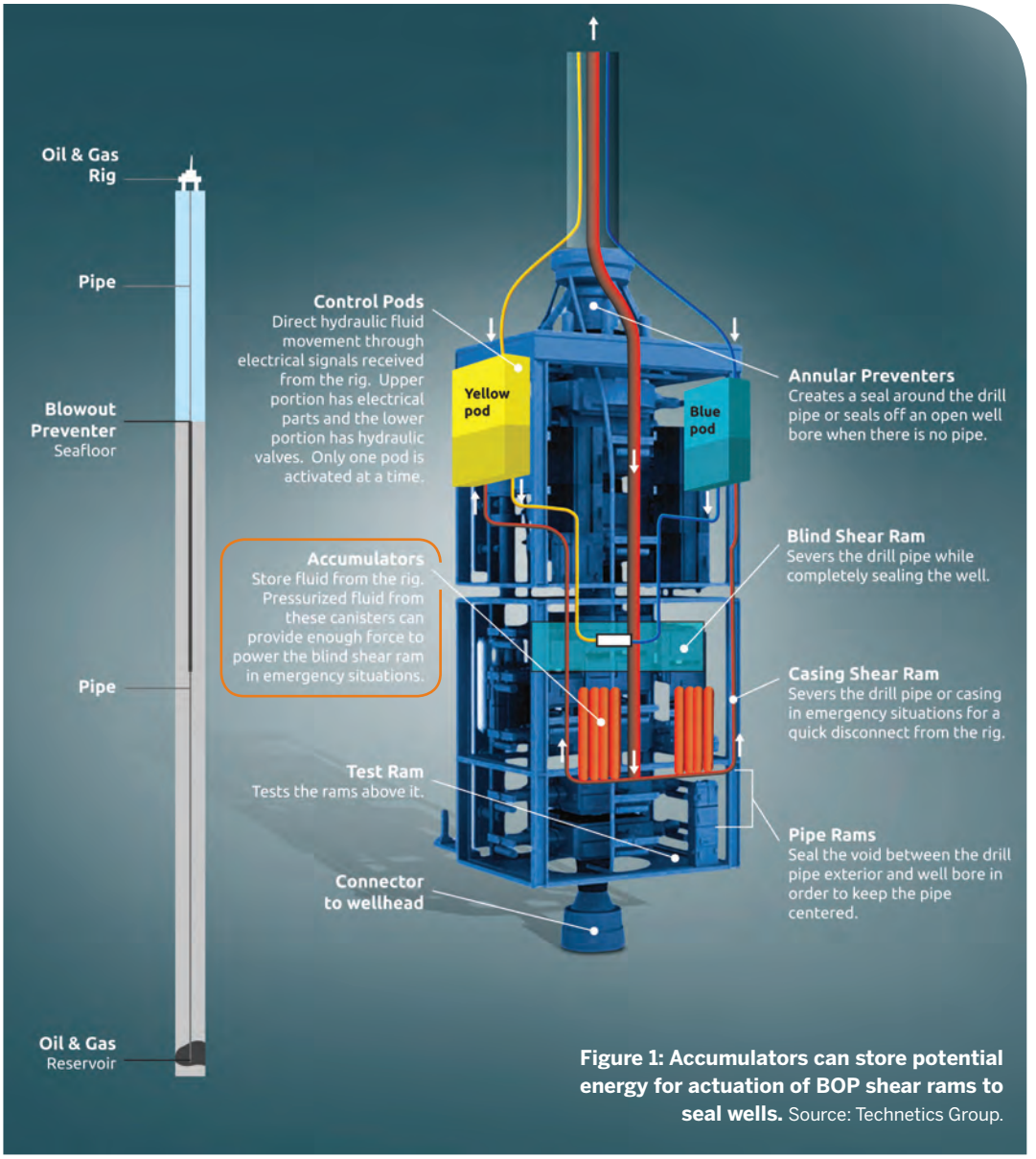

Figure 1: Accumulators can store potential energy for actuation of BOP shear rams to seal wells. Source: Technetics Group.

Thermal-compensation accumulators are required to accommodate fluid expansion and contraction due to temperature changes in the environment or operating conditions. These accumulators also can be used to store extra fluid in case of leaks in the system.

Energy-storage accumulators can be used as a backup in the event a pump fails, or to temporarily provide a higher flow rate than the pump can supply, much like a capacitor in an electrical system. These accumulators store potential energy using compressed gas or a spring to supply hydraulic pressure to a system on demand. One such instance is actuation of the shear rams on blowout preventers (BOP) to seal off wells, even during a loss of power, Figure 1. A bank of accumulators stores a large volume of hydraulic fluid at high pressure

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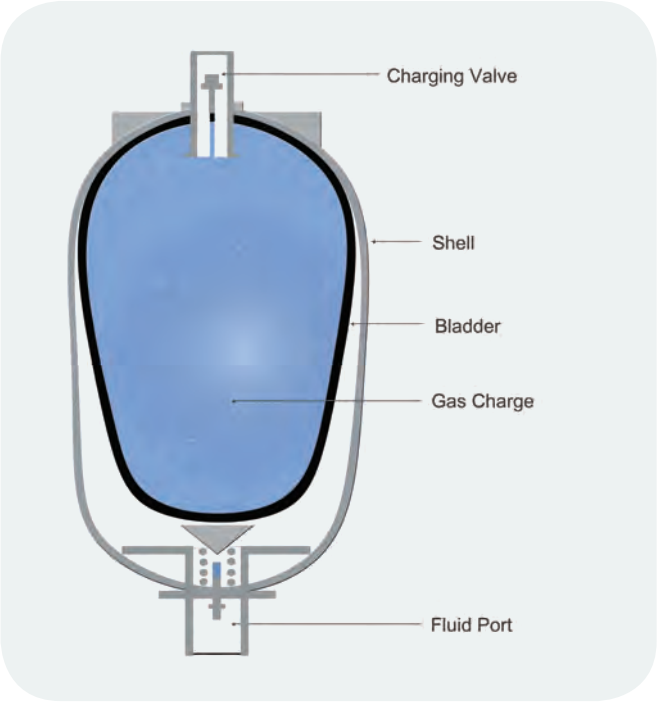

Figure 2: Bladder accumulators balance pressure on either side of the bladder. Source: Technetics Group.

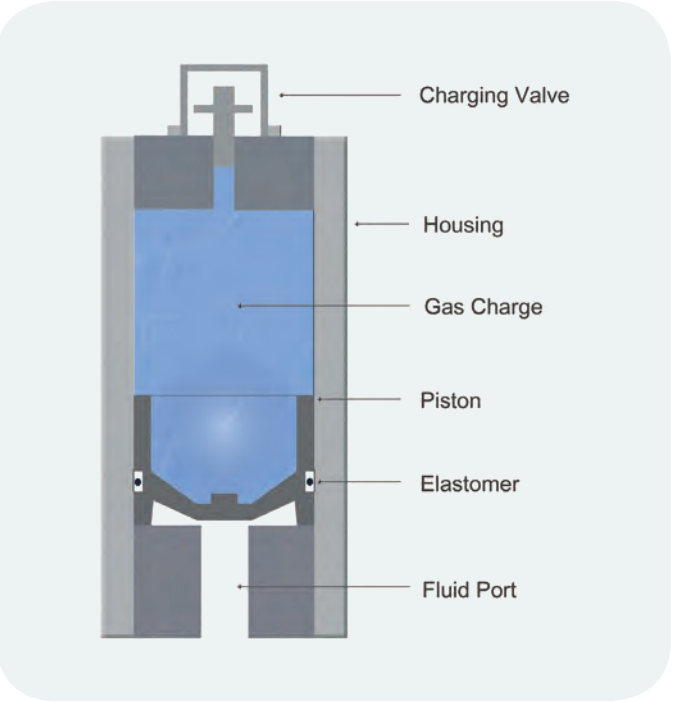

Figure 3: Piston accumulators offer high reliability and can outlast bladder accumulators. Source: Technetics Group.

that can quickly be discharged to power the shear rams without the need for pumps or power. Since a blowout preventer operates on the ocean floor, a great deal of expense is incurred when maintenance is required. Servicing a BOP requires the use of ROVs or removal of the system to the surface. While the BOP is offline, the well is also offline, which costs a great deal in lost production and maintenance expense.

In addition, providing a steady pressure to hydraulic components such as actuators and valves can considerably improve performance and accuracy. An accumulator can be installed near pumps and other devices, which produce pressure transients, as a damper to reduce spikes and pulsations for longer system life. The addition of an accumulator in the system may result in increased system weight.

Suitable for use in any of these applications are bladder, piston, or bellows accumulators. In addition to these types, there are several others not discussed. All function essentially the same, except for how they separate compressed gas and hydraulic fluid.

Bladder accumulators

Bladder accumulators typically consist of a pre-charged pressure vessel, elastomeric bladder, fluid port, and gas-charge service port. As system pressure increases, the fluid compresses the gas and the bladder, which acts as a barrier between the fluid and gas. Pressure is balanced on both sides of the bladder, Figure 2.

This type of accumulator offers a number of advantages. Besides being the lightest and least expensive option, bladder accumulators can be designed to fit into a smaller envelope than piston or bellows accumulators. They also provide high reliability with regular maintenance.

Unfortunately they lose their precharge over time, due to the permeability of the elastomer. As a result, they need to be repressurized periodically to ensure safe operation. In addition, bladder materials are not compatible with corrosive environments such as hydrogen sulfides, sour gas, and others.

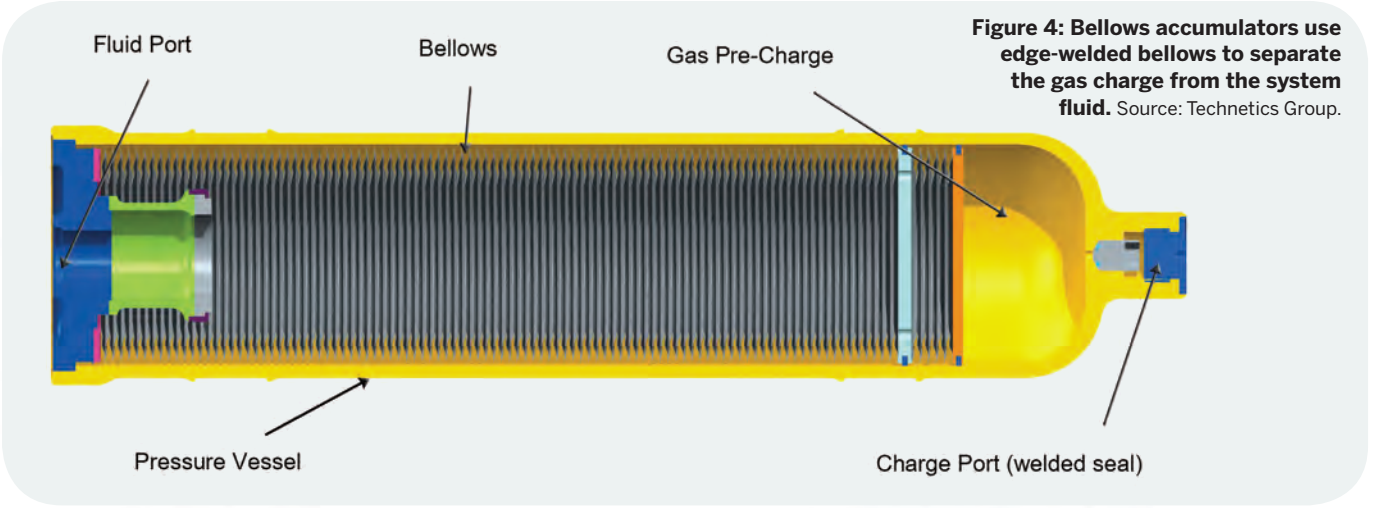

Figure 4: Bellows accumulators use edge-welded bellows to separate the gas charge from the system fluid. Source: Technetics Group.

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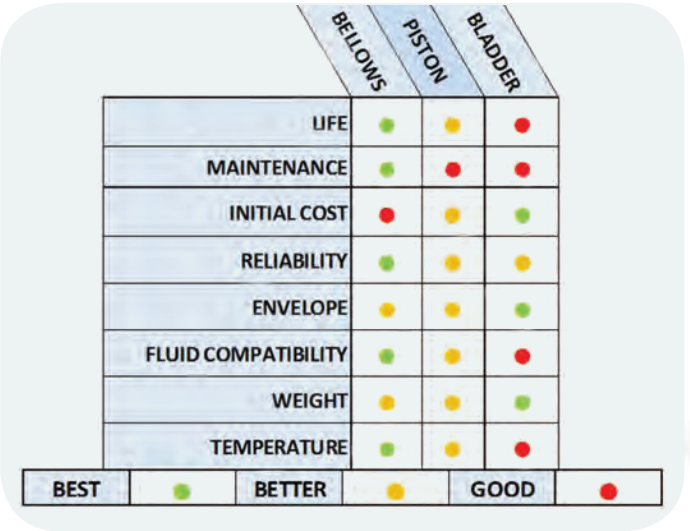


Figure 5: Accumulator can be tailored to the project's need. Source: Technetics Group.

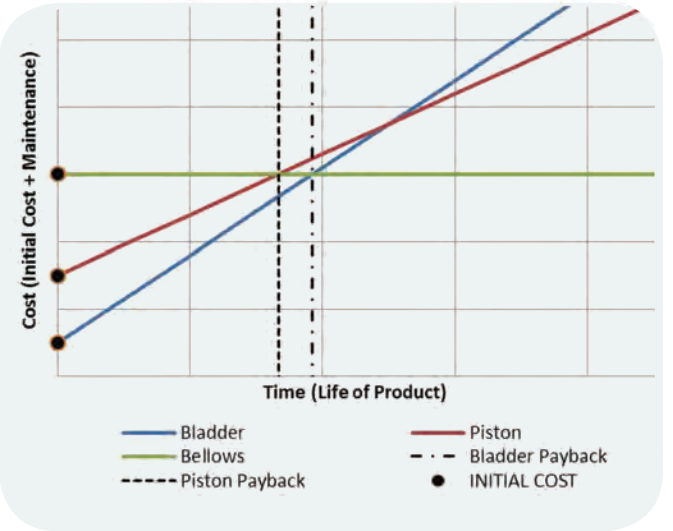


Figure 6. This comparison shows the cost vs life of the different accumulator types. Source: Technetics Group.

Bladders must be replaced from time to time, which requires taking equipment offline.

Piston accumulators

Piston accumulators similarly consist of a pre-charged pressure vessel, fluid port, and gas-charge service port or valve, Figure 3. But instead of a bladder, they use a metal piston with an elastomeric or non-elastomeric seal. As system fluid pressure increases, the gas is compressed by the sliding piston and dynamic seal. Provided the friction is low, the pressure on both sides of the piston is essentially balanced.

These accumulators are relatively inexpensive, can outlast bladder accumulators, and can fit in a smaller envelope than bellows accumulators. With fewer components they also offer high reliability with proper maintenance. However, as with elastomeric bladders, typical piston seal materials are not compatible with some fluid environments and have a more limited temperature range, when compared to metal bellows. In addition, the piston seals must be replaced periodically, which can be quite costly when operating on the ocean floor, as it requires bringing the accumulator to the surface. And like bladder accumulators, piston accumulators tend to lose their pre-charge, requiring periodic repressurization.

Bellows accumulators

Bellows accumulators consist of essentially the same components as bladder and piston accumulators, but use edge-welded bellows to separate the gas charge from the system fluid, Figure 4. As the fluid pressure increases, the extending bellows compresses the gas.

Provided the bellows have a low spring rate, pressure is essentially balanced on both sides. Since no permeation or dynamic seals are involved, bellows accumulators can be designed to provide extremely long life.

Among the major advantages offered by bellows accumulators is the fact that they are maintenance-free and do not require recharging. The bellows form a hermetic seal between the gas charge and the fluid, allowing them to remain in service for the life of a system without loss of the gas pre-charge. In addition, a service-gas port can be used to produce a variable pre-charge to accommodate different service depths. Moreover, bellows can be made of corrosion-resistant materials to withstand extreme environments that bladder and piston accumulators cannot.

However, bellows accumulators are more labor-intensive to produce than bladder and piston devices, and in general cannot be repaired if the internal components are damaged.

They also may require a slightly larger envelope than the other types.

Choosing equipment

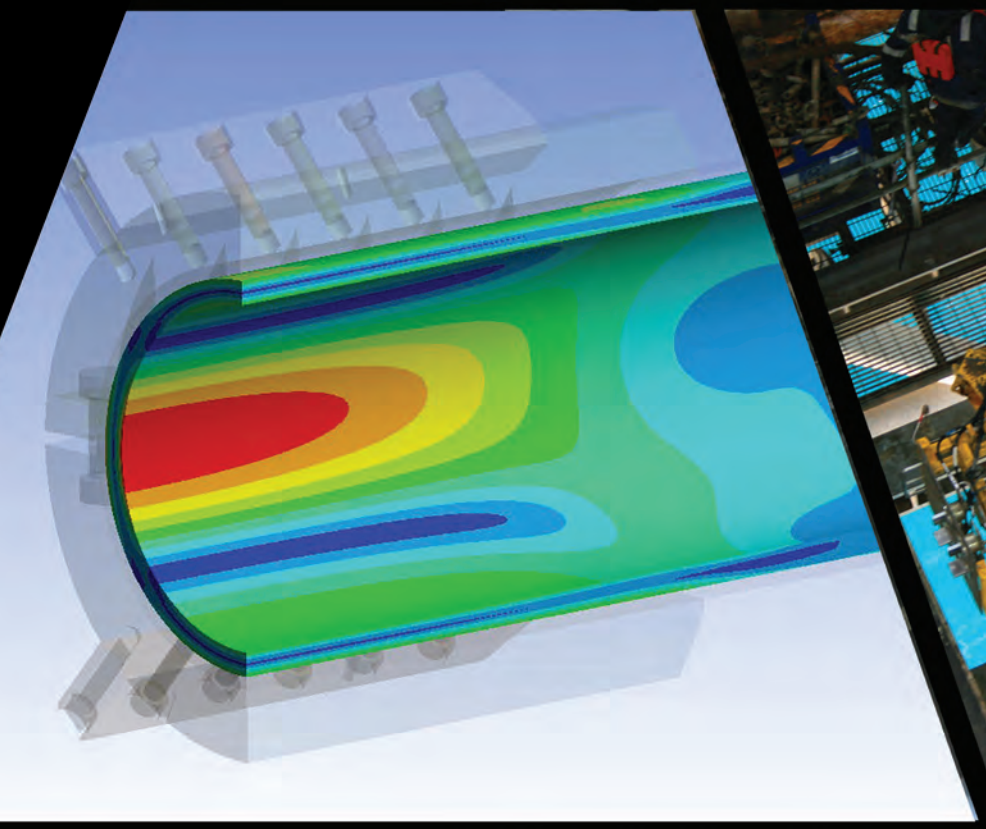
As the demand for oil and gas increases, the industry is moving into deeper waters and more extreme environments. As a result, the equipment used in these applications is being pushed to its design limits. Determining the type of accumulator best suited for an application depends on a number of factors, notably the importance of reliability, cost of maintenance and the environment in which it will operate. Figures 5 and 6 provide a summary comparison of the different types of accumulators in terms of these and other factors.

Bladder or piston accumulators can be used for applications where they can be easily accessed for maintenance, loss of the gas charge is not critical, and the environment is not extreme. However, where maintenance shutdowns are prohibitively costly, the risk of failure is great, and the operating environment is extreme, bellows accumulators are the best solution. **OE**

Aaron Glafenhein *has a BS degree in Astronautical (Aerospace) Engineering from Embry-Riddle Aeronautical University, Daytona Beach. He has worked on HPMFAs for NASA SLS and Ares rockets, Airbus A350 and the F-35 Joint strike fighter. Aaron has been with Technetics Group for almost four years.*

Tim Leister *has been with Technetics Group eight years and has a BS degree in Mechanical Engineering from Purdue University.*

Aquaterra ENERGY



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NEW THIS YEAR!

A half day interactive special session on Tuesday, September 24th:
"Mooring Systems-Issues, Concerns and Solutions"
Speakers include Subir Bhattacharjee, Exxon; Kai-Tung Ma, Chevron; Hongbo Shu, Shell, Arun Dugal, Sofec; Kent Longridge, Intermoor; Andrew KIlner, AMOG; and more!

Forum keynotes include Bernard Van Leggel, Managing Director, SBM and Blake Moore, Project Engineer / Manager - Stones FPSO, Shell!

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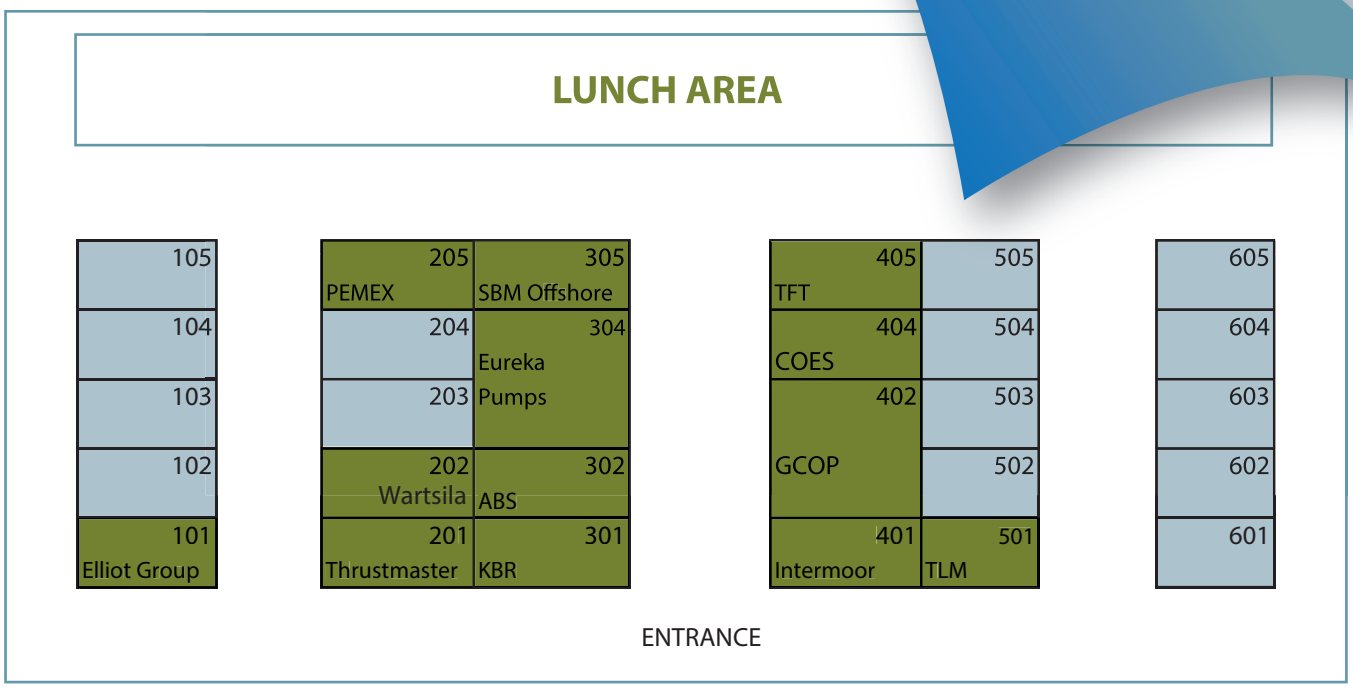
2013 Emerging FPSO Forum

Exhibit Hall Floor Plan

Galveston Convention Center
September 24-26th



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Preliminary Agenda

DAY 1 Tuesday, September 24th

1:00 - 5:00pm	**Special Session: "Mooring Systems** • Issues, Concerns and Solutions	**Session Chairs:** Arjan Voogt, Marin USA/ David Cobb, Intermoor/ Christy Lan, BSEE
1:30 - 2:30pm	**Session Breakdown:** • The Most Important Mooring Issue	- Subir Bhattacharjee, Exxon/ Kai-Tung Ma, Chevron/ HongBo Shu, Shell/ Arun Dugal, Sofec
2:30 - 3:30pm	**Mooring Intergrity** • A Practical Approach to Mooring Integrity Management • An Update on the API 4F Guidelines on Chains and Connectors • Overview of Findings within the SCORCH JIP	- Kent Longridge, Intermoor - TBD - Andrew Kilner, AMOG
3:30 - 5:00pm	**Design and Specifications** • Installation Procedures • Design Specifications including new API RP2SK • Design Challenges, Larger Disconnectable Buoys Require New Assessments	- Jennifer Tule, Anadarko - Hongbo Shu, Shell - MARIN or SBM (to be confirmed)
5:00 - 7:00pm	**Opening Night Reception on the Exhibit Floor**	

DAY 2 Wednesday, September 25th

7:45 - 8:00am	**Introduction and Opening Remarks**	- Joe Lovett, Senior Industry Consultant
8:00 - 8:30am	**Keynote:** • The World of FPSOs: Trends Today and Outlook for Tomorrow	- Bernard Van Leggelo, SBM
8:30 - 9:50am	**Session I: The State of the Business** • Is it Healthier this Year than Last Year? • Own or Lease in Today's Business World • Redeployment Realities	**Moderator:** Peter Lovie, Peter M. Lovie PE, LLC. - Stuart Bannerman, BW Offshore - Boyd Howell, Modec - Cobie Loper, SBM Offshore
9:50 - 10:20am	**Morning Coffee Break in the Exhibit Hall**	
10:20 - 11:40am	**Session II: Financing & Planning Risky Business** • Industry Outlook: Active Projects in the Decision Making Process • Shipping and Offshore Market Trends in Stormy Weather • FPSO Industry Finance Outlook	**Moderator:** Barry Donovan, Raymond James - Jim McCaul, International Maritime Associates - Barbara Gronquist, Det Norske Bank - TBD
11:40 - 1:10pm	**Lunch in the Exhibit Hall**	
1:10 - 2:55pm	**Session III: Execute or Die** • Growing Recognition of Project Management as Critica Discipline • Keeping Score on FPSO Projects • FEED, Definition, Operator Objectives and Practical Realities • Contracting It-Strategies that have worked for FPSOs • Panel Discussion	**Moderator:** Dick Westney, Westney Consulting - Dick Westney, Westney Consulting - Jonathon Walker, IPA - Lawnie Sturdevant, Modec - Mike English, Senior Industry Consultant
2:55 - 3:25pm	**Afternoon Break in the Exhibit Hall**	
3:25 - 5:00pm	**Session IV: Pioneers Overcome their Challenges** • **Round is Good:** The Contractor's Journey • Dealing with Gas Pains in Offshore Oilfield Developments • Concept into Practical GTL Plant for FPSOs	**Moderator:** Jim Wodehouse, Water Standard - Fredrik Major, Sevan - Ian Baxter, Compact GTL - Jeff McDaniel, Velocys
5:00 - 7:00pm	**Reception on the Exhibit Floor**	

3rd Annual

emerging FPSO forum

DAY 3 Thursday, September 26th

8:00 - 8:30am	**Keynote: Shell's Choice for an FPSOs at Stones**	- Blake Moore, Shell
8:30 - 9:50am	**Session V: FPSO Operations in the GoM** • FPSO Operating History on First FPSO in GoM • Working with the Regulators on Operations – 2013 Realities • Contrast with FPSO Operations in Mexican GoM • Panel Discussion	**Moderator:** Kirk Barlass, BW Offshore - Harry Leonard, Petrobras - Partha Ganguly, Petrobras - Kirk Barlass, BW Offshore
9:50 - 10:20am	**Coffee Break in the Exhibit Hall**	
10:20 - 11:40am	**Session VI: Rules and Regulations** • Update of FPSO application process and an overview of any revised standards and regulations • Overview of the statutory compliance process for floating structures in US GoM • DNV Approach to Deepwater FPSOs and Conversions • **Panel Discussion:** What's ahead in the GoM with Regulators/Classification Societies	**Moderator:** Peter Noble - Christy Lan, BSEE & CDR James Rocco, USCG - Ken Richardson, ABS - Kenneth Vareide, DNV North America Maritime
11:40 -1:00pm	**Lunch in the Exhibit Hall**	
1:00 - 2:20pm	**Session VII: FPSO Offloading in GoM** • Living in the Jones Act World and experiences at Cascade/Chinook • Economics, Performance - Four Options for US GoM Offloading • Contrast - 14 Years of High Volume Offloading in Mexican GoM	**Moderator:** Jeremiah Daniel, Petrobras - Eric Smith, OSG - Peter Lovie, Peter M. Lovie PE, LLC. - Lawnie Sturvedant, MODEC
2:20 - 3:30pm	**Session VIII: Closing Session** • **Operator Panel:** What's Ahead • **Tying it all Together:** Wrap Up and Closing Remarks	**Moderator:** Blake Moore, Shell - Shell, Petrobras, Conoco, Chevron

For more information about the conference contact:
Contact Lisa Zadok at
713.874.2215 or
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The heave compensation conundrum

(L) Patrick van Eerten, director offshore, Jumbo, and (R) Huisman chief executive Joop Roodenburg.

Active heave compensation has become a must-have for offshore lifting and landing. But is it the best solution?

Heave compensation systems were introduced to the offshore market in the early 1980s to enable the safe landing and lifting of loads. Since then, heave compensation systems have developed extensively and are considered essential tools for offshore lifting and landing.

However, selecting the right system for the right job is not as simple as it seems and opinions vary over the benefits, or otherwise, of different systems. Equipment builders, operators and clients often have a different perspectives and interests.

OE asked director of operations and offshore at Jumbo Shipping Patrick van Eerten and Huisman chief executive Joop Roodenburg to give their views on the benefits and drawbacks of passive and active heave compensation systems.

Roodenburg—Huisman

Huisman chief executive Joop Roodenburg

Active and passive heave compensation work with completely different principles.

Passive heave compensation (PHC) acts as a gas-loaded spring system, reducing the dynamic forces on the load. It does not require an input signal and is therefore also called passive constant tension.

PHC systems use a large hydraulic cylinder, which balances the load using nitrogen gas. The cylinder is connected via a medium separator to an accumulator, which is charged with the gas. There is no active control over the position of the load and the movement of the load during lowering depends on external forces, like drag and inertia.

PHC is reliable, simple and doesn't require power to operate. This is a major advantage because the system will continue to operate even during a power failure. PHC, however, is limited because there is no control over the position of the load and it is less effective on objects with little drag.

Huisman introduced active heave compensation (AHC) on its cranes in 1984. AHC is position-control of a load. The vessel's motions are measured using a real-time signal from a motion reference unit (MRU), which is used to actively control the position of the load, so that it remains at a selected position.

AHC is generally performed using electronic or hydraulic winches. By paying-out or reeling-in wire, according to the MRU measurements, the position of the load is controlled. The winches have virtually unlimited stroke and are simple to operate.

They do, however, require a lot of power and there is no back-up during power failure. Also wear of the wire rope on the drum (known as drum crushing) is a drawback of this application. However, AHC can also be designed using a cylinder.

Both active and passive heave compensation have their advantages and their limitations. So, to have the best of both worlds, Huisman designed

Van Eerten—Jumbo

Patrick van Eerten, director offshore, Jumbo

There has been a growing interest in AHC systems, as well as combined AHC and PHC systems, with many tenders today specifying AHC systems.

However, very few [people] actually understand these systems. While AHC systems have many advantages, we see several limitations to their use.

Jumbo prefers an engineered-solution, using PHC, based on experience of maritime heavy lifting and ship motion. Lessons learnt have led to the development of calculations to fine-tune the interaction between heavy lifting and ship motion.

The motions are carefully calculated during the engineering-phase of a project, leading to a tailored passive compensator [that is] able to accomplish a desired landing speed at the ideal pressure balance for different circumstances.

Once overboard, the hydrodynamic forces are relatively easy to overcome as drag and added mass can be fairly accurately predicted and total forces can be absorbed or minimized.

For example, landing speed can be achieved at below 0.5m/s with good resistance control, using a far less complex, more robust and safer system than AHC.

PHC is a very straightforward hydraulic cylinder and a gas accumulator. The piston's load is balanced by nitrogen pressure and the stiffness depends on the nitrogen volume.

As the load is compensated at exactly the same frequency as the motion of the waves, there is hardly any risk of resonance. In an AHC system, resonance is hard to manage and, when it occurs, the damage can be substantial. When using PHC, the load also remains stationary after landing.

The hoist and heave systems are independent, making the system safer. PHC can also be used with a "normal" crane, simply by adding a heave compensation cylinder. PHC also requires no external power, making [possible] the design a fail-safe system to reduce wave impact on subsea operations.

There are some instances where you have to use AHC, no doubt. But, in general, you do not need it.

More advanced equipment, technology, and offshore lifting procedures can be the right answer, but there is no need for it to be too complex. Preparation of equipment, personnel, and procedures are what are important. ■

and built a combination of both systems on our offshore cranes.

The system comprises of a large hydraulic cylinder working in parallel with two smaller cylinders. The larger cylinder serves as the major load-bearing component and is used for passive heave compensation.

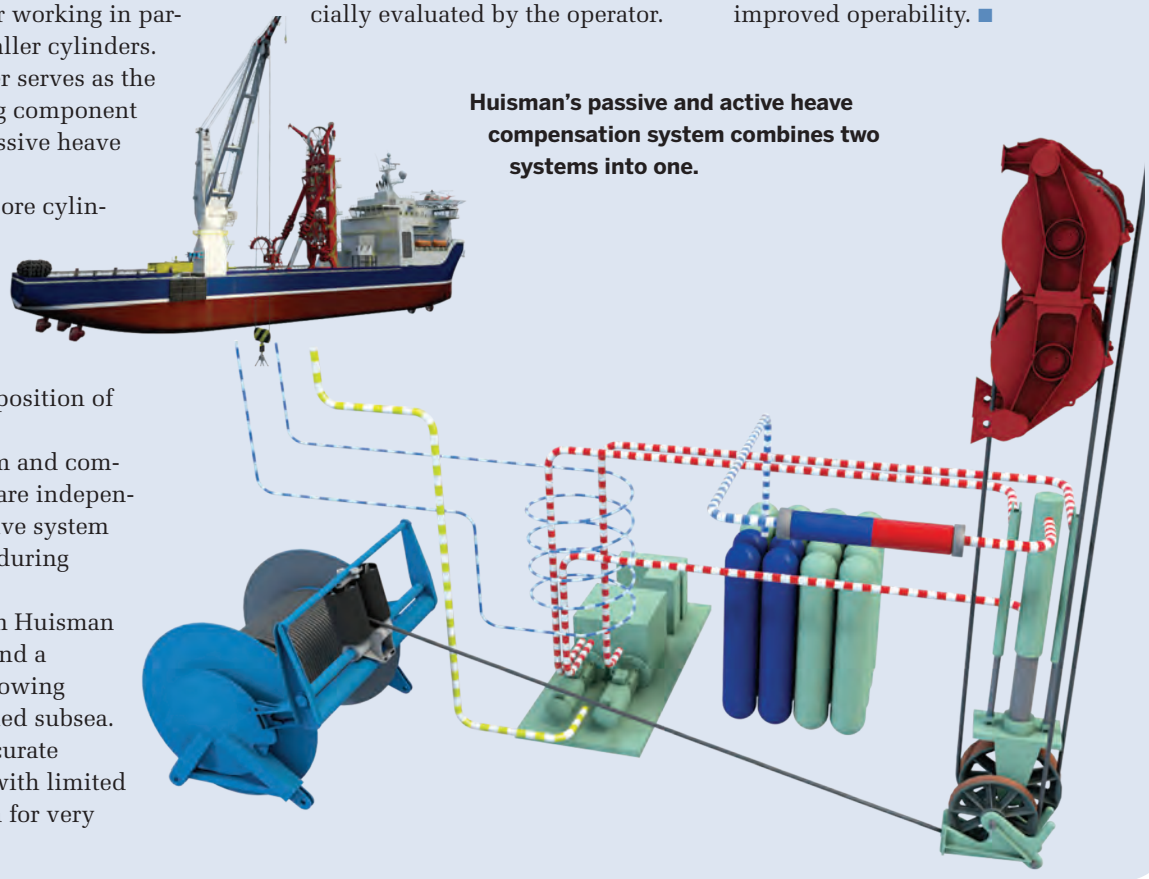
The two small bore cylinders are used to actively control the position of the large cylinder, and consequently the position of the load.

The hoist system and compensating system are independent and the passive system provides back up during power failure.

With this system Huisman believes it has found a solution for the growing loads being installed subsea. It provides the accurate position control, with limited power usage, even for very large loads.

Both AHC and PHC systems have advantages and disadvantages, which should be considered and commercially evaluated by the operator.

We believe in the combination of both systems to increase the value of offshore installation vessels through improved operability. ■



Huisman's passive and active heave compensation system combines two systems into one.

Advances in bollard pull testing technology

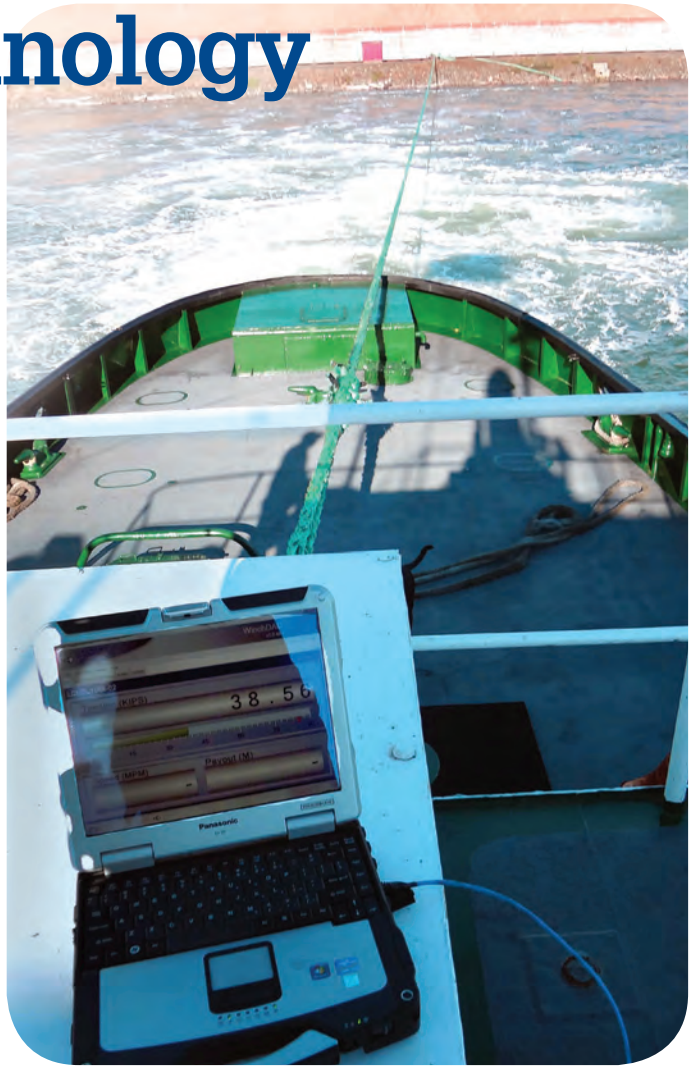
By Tom Rezanka, MTNW

Many arguments about the capabilities of a tug can be quickly settled when you can conduct a full-ahead power, bollard pull test.

"Many captains will argue about horsepower, hull design, rudder angles, and other variables, but the only thing that really matters is bollard pull and a test provides empirical data of pure power," says Mark Babcock, VP of Machinery for Sause Brothers' 200 tugs, barges and OSVs. "A well-maintained vessel shouldn't lose bollard pull over time, but with every propulsion-related change, engine overhaul, shaft or propeller retrofit, the vessel should be re-tested."

The bollard pull test has been around for many decades, but recent changes in technique, technology, and data-logging allows engineering and operations to fine tune the analysis and provide more precise information. Providing accurate reports allows pilots, agents and customers to have confidence in towing and tug capabilities at the edge of the performance envelope.

"While many new tugs are built larger and more powerful than ever before, most of the tugs on rivers and ports have years on their engines and the ability to move their tow when it ultimately matters, should be tested against expectations," said Babcock.



Changes in technique, technology, and data-logging allows finely tuned analysis of bollard pull tests.

Background

Bollard pull is the static force exerted by a tug at zero speed on a fixed line. Almost always, a test involves affixing a line to a shore-based *bollard* (a short, vertical post) and ramping the RPMs of the engine to full- throttle, typically in ahead and astern conditions.

The vessel is then held at full RPMs between 1 and 10 minutes. Some versions of this test are completed quickly and some, like those in Brazil, last over an hour.

Influences

Many variables can influence a bollard pull test reading, including water depth, prop wash, wind, tidal forces or currents, rudder angle, and stretch of the tow line. Finding an ideal site is difficult, so these external forces must be figured into the final analysis.

Equipment

A bollard pull test requires a tension sensor which is put in series with the tow line, a local display of the line tension, and a process to record that data. Often, an engineer will be present in the engine room to evaluate engine RPMs and another engineer will stand on the back deck to track the forces on the load cell by noting them on a display and manually tracking the figures by hand.

This handwritten process can be challenging and inaccurate in rough weather and in river conditions in which forces on the line change quickly. In river situations, the tug captain may start upriver of the shore-based bollard, bringing the tug up to full power. When the vessel is perpendicular to the shore, the engineer must quickly capture data from the tension sensor. This short time window means it can be challenging to capture accurate data.

Technology advances

Measurement Technology NW, based in Seattle, WA, has developed a PC-based software solution that allows data capture up to 100 times per second (Hz). The software time-stamps the incoming data so that it is easy to

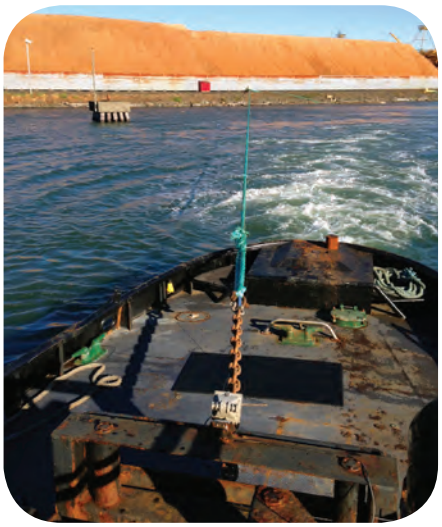
match up with other data in post-event analysis back at the office, automating and simplifying data correlation.

Recently, MTNW supported the Glosten Associates work with a tugboat bollard pull test in Coos Bay, Oregon. The trials were to test and verify the bollard pull of a number of tugs. "The MTNW tension monitoring system and engineer provided the tension data that we required to perform our analysis," said Ken Lane, Director of Production Services at Glosten. "The MTNW system captured the line tension data with an accurate time stamp, which allowed us to easily synchronize the tension sensor data with other important measurements."

MTNW's tension monitoring systems include a certified tension link, rugged waterproof local display, and a laptop PC with data-logging software. "The system is plug-and-play for quick set up, allowing for more time testing and lower fuel costs. The engineer can now watch the tension locally, but also know that the data-logging software is catching every tension spike for post-test analysis," said Tom Rezanka, Vice President MTNW. "The equipment can accommodate tests as simple as full ahead or full astern to the more complicated tests that seek to correlate line tension to engine RPMs and other variables. The WinchDAC software prints easy-to-read PDFs of each test."

Software allows data capture at 100 times per second.

MTNW's equipment is available for other engineers and operations teams to use. "Over the years, we have offered equipment for bollard pull testing and certification for tugboats and now we have invested in and made available a fleet of rental devices so that more naval architects, tugboat operations managers, and engineers can perform these services on their own," said Tom Rezanka, Vice President MTNW.



In river tests, the tug stars up river from the bollard, so that an engineer can take readings when the vessel is perpendicular to the shore.

MTNW's equipment is certified regularly and MTNW will work with certifying witnesses from DNV, ABS, Lloyds, Bureau Veritas and any other required certifying body. OE

Heerema Marine Contractor's new-build *Aegir* is at Huisman's yard in the Netherlands having its multi-lay pipelay system installed. The vessel is due to set sail to the Gulf of Mexico in September, with her first project working for Anadarko, Lucius.

Heavy lifting gets versatile

The global offshore heavy lift market is fragmented, but evolving, with new vessels expected to bring a step change in capability and flexibility. Elaine Maslin reports.

Offshore heavy lifting capability has increased in waves, from the early heavy lifts of just a few hundred tonne, to a step up to 5000 tonne in the late 1970s, and then topping 10,000 tonne in the 1980s.

Floatover lifting, using barges and then vessels, including for transport, has since emerged as the dominant force in the ultra-heavy lift market, taking lifting capability up to 30,000 tonne.

Change is coming once more, but, says Peter Baggaley, managing director at London Offshore Consultants, it is more about harsh and deepwater capability, and confidence in engineering than new technology.

A step change in capability will come from Allsea's dual-hull *Pieter Schelte* (OE, May 2013), in the ultra-heavy lift space, and an emerging fleet of more versatile heavy lift vessels, fitted with pipelay and subsea lifting capability, Baggaley says.

"A lot of technology is coming together [on the *Pieter Schelte*] to come up with a vessel that can do transportation, as well as installation, in deepwater harsh environments using dynamic positioning," he says. "That gives a lot more scope and availability for operation."

"What we are also seeing, in terms of development, is for [3000-5000-tonne] heavy lift vessels to be much more flexible. We have the *Aegir* (*OE*, April 2012) coming from Heerema Marine Contractors, for example. It has heavy lift capability of 4000 tonne, but it is also a pipelay vessel that can reel-lay and J-lay and perform deepwater installation down to 3500m. This is not new technology, but putting the technology together is new and the scale of the vessels is new."

Baggaley says that engineering solutions are also becoming smarter as contractors are involved in projects earlier, in turn increasing confidence in lifting operations.

The ship-shape segment of the heavy lift market has seen growth, and good utilization rates, especially those with lifting capacity of more than 2000 tonne, says Gregory Brown, consultant at Infield Systems.

The global fleet in this segment has risen from 12 in 2008, to 20 this year, according to Infield. This includes the new combination-type vessels, such the *Aegir*, which is due to start its first contract working for Anadarko in the Gulf of Mexico this autumn.

Overall, the offshore lifting market is dominated by an aging fleet of low-end shallow water-focused units with lift capacities below 1000 tonne, mostly lift vessels and barges built in the 1970s and 1980s, Brown says.

Many were operating in the US Gulf of Mexico, but moved to more benign water areas including Southeast Asia – where the strongest demand lays – the Middle East and Mexico, after conventional activity plummeted following the onset of onshore shale gas in the US. These units, while still in use, have low utilization rates.

The 5000-tonne and higher market, dominated by traditional derrick crane lift semisubmersibles, such as Saipem's *Saipem 7000* and Heerema Marine Contractor's *Thialf*, has also remained flat, with little new tonnage introduced, due to limited work and the finance required to fund a new build, Brown says.

Lifting capacity in this segment has

also plateaued at about 11,000 tonne due to physical limitations, Baggaley says.

Instead, lifting capacity growth comes from the now-established floatover market, with the use of rapid ballasting on purpose-built vessels and barges to control the crucial touch down phase. Offshore lifts of integrated decks have already been performed at approaching 30,000 tonne, Baggaley says.

The largest growth segment in offshore lifting has been in jackups, according to Infield. The number of units is expected to reach 37 in 2014, from just eight in 2008, but then plateau until 2017.

These units have been built mostly to serve the European offshore wind installation market, driven by orders from Seajacks, Fred. Olsen, Windcarrier and Swire Blue Ocean, Brown says, with some heading to Southeast Asia for use installing oil and gas facilities.

Regionally, by 2017, Asia is expected to have the highest demand for heavy lift vessels, based on vessel days, at 3685, compared to 3345 predicted this year, according to Infield. Close behind Asia is Africa, with demand of 3493 vessel days expected in 2017, a significant increase on this year's 995; this is followed by North America, with demand for 3317 vessel days in 2017, up from 2171 in 2013. Europe and Australia will see increases in demand, but at lower levels. Latin America will remain close to a peak of 1721 reached this year until 2017.

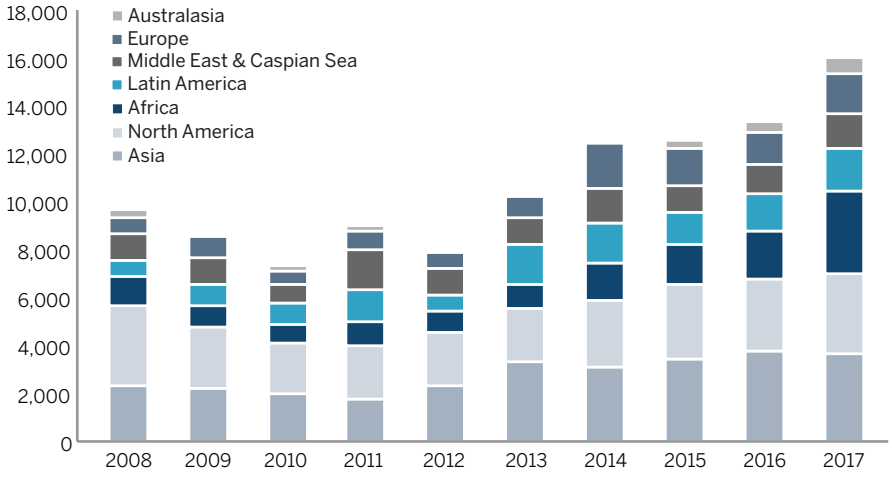
Based on market share, demand will nearly double between 2013 and 2017 for subsea installation, from 1326 to 2418 vessel days. Most of the demand in 2017 will still be for platform installation, at 8640 vessel days, followed by platform removal, at 3923 vessel days.

The offshore decommissioning market had been expected to drive demand for offshore lifting. However, it has yet to materialize on a significant level, due to continuing high oil prices pushing cessation of production dates further out, Brown adds.

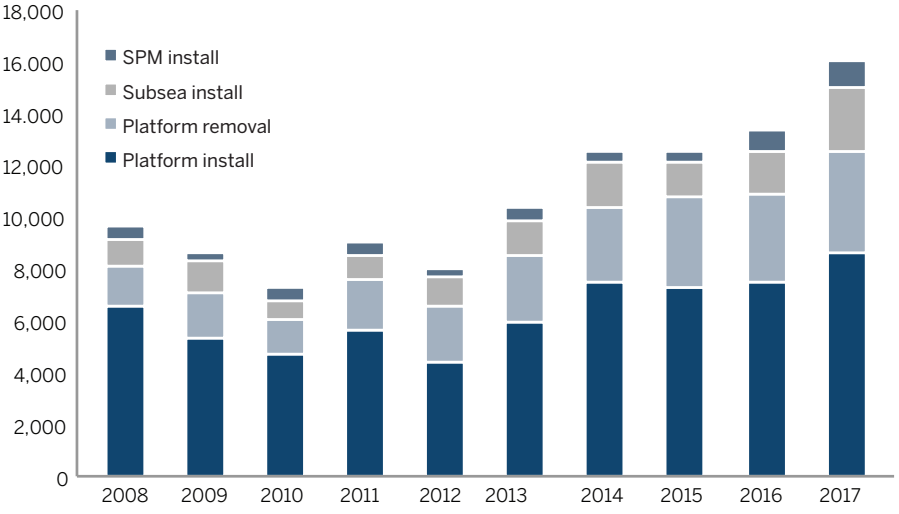
Looking ahead, Baggaley says challenges for the market will include operating in arctic waters. At issue in particular, the speed at which weather changes in the Arctic. Other challenges Baggaley sees are the competency of newer operators working in the offshore renewables sector, and not working at the high standards expected for offshore.

A further concern is the use of dynamic positioning (DP), specifically, understanding its capabilities. He says he has had experiences where a vessel, with DP2 capability, has been selected for a project without the operator realizing that the system would not meet the requirements needed because the capability is not through the full range of the compass. OE

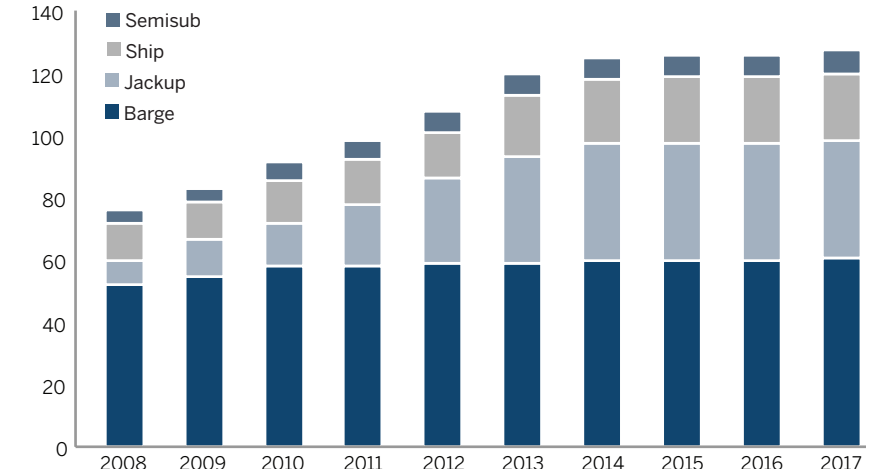
Heavy-lift demand (vessel days) by region



Heavy-lift demand (vessel days) by market sector



Heavy-lift vessel supply (units) by hull type



The Åsgard subsea compression template was installed in June using the Saipem 700. Credit: Oyvind Hagen/ Statoil.

Statoil's subsea process intervention challenge

As subsea production systems are entering a new era, Statoil is finding that designing, qualifying and installing the subsea factory is just the start—the future will require a new breed of vessel, Elaine Maslin explains.

Earlier this summer, one of the key building blocks to creating what will be the world's first subsea compression project was installed in 300m (984ft) of water, about 200km offshore Norway.

By late 2014, the 74m-long, 45m-wide and 26m-high Åsgard subsea compression station frame will contain multiple modules.

Nearby will also be the manifold frame. Together, they will house 22 modules, including a two compressor modules, at 289-ton and 12x8x11m each.

The project, which will enable the recovery of an additional 280MMboe from the Midgard and Mikkel satellite reservoirs at Åsgard, has involved years of research and qualification.

Now, with first production approaching (early 2015), operator Statoil is addressing the next challenge: future intervention and maintenance needs on the field.

North Sea Shipping's multi-purpose vessel *North Sea Giant* will be used to install the modules into the Åsgard subsea frames.

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So far, Statoil's conclusion is that the type of vessel it needs to remove and redeploy modules on Åsgard, particularly the compressor modules, is not currently available.

Statoil is not alone. As part of its own assessment of the potential future use of subsea compression on the Ormen Lange field, which came on stream in 900m (2853ft) water off Norway in 2007, Shell Norske also concluded current IMR (intervention, maintenance and repair) vessels would not meet requirements.

Speaking at Underwater Technology Conference 2013 (UTC) in Bergen in June, Raimund Bjordal, technical lead, subsea processing intervention, at Statoil, says: "We are moving towards a complete subsea factory and we need to take the next step, we need an intervention vessel that can handle what is needed for the subsea compression plant and also for future subsea templates."

Jarand Rystad, managing partner, Rystad Energy, says that the time has already come, however.

"Now [existing] subsea installations are starting to mature, we are starting to see all of the problems we have already seen on the topsides for a number of years," he told UTC attenees in Bergen.

"To be honest, the [subsea] industry has not been ready for this. It needs to move more from a greenfield industry to a maintenance industry, and that requires quite a different mindset."

An "interim solution" will be used for the installation of the compressor train modules on Åsgard next year, Bjordal says. Technip, the installation contractor, will use the DP3 *North Sea Giant*, built in 2011 with 2900sq m of deck space, a 400-ton crane and an over-the-side, subsea handling system designed specifically for the Åsgard project.

For future intervention work—lifting and replacing modules—both Statoil and Shell have looked at the use of a monohull vessel, with a focus on deck space and a large moonpool.

Shell has looked at existing construction and IMR vessels and their capacities, including the *Skandi Achiever*, the *Island Constructor* and the *Viking Poseidon*.

Mathias Owe, Ormen Lange subsea compression project manager, says the options are to agree to a contract for use of a newbuild, or conversion, with a vessel operator such as Subsea 7, or to build a new ship, potentially cooperating, or sharing it, with Statoil.

In case it decides to use subsea compression on Ormen Lange, Shell has based a potential design (able to handle modules on the project) on the Subsea 7 vessel *Seven Atlantic*. It would be 133.4m long, 28m wide, able to carry up to six modules on deck, and incorporating a moonpool that could take 12m by 6m by 12m modules.

Statoil has done a similar exercise. It says the vessel it requires, described as a subsea processing intervention (SPI) vessel, would need to be able to work year round, in up to 4.5m waves, and lift modules of up to 400-ton and 15m-long by 12m-wide by 12m high.

It would also need to be able to execute subsea processing-related activities, including handling hydrocarbons, nitrogen gas, and MEG. This would require MEG and nitrogen pumping spreads, a reclaimed oil sump, and a cold flare system.

Potential options assessed by Statoil include a construction vessel with over-the-side handling system or a newbuild vessel with a large moonpool.

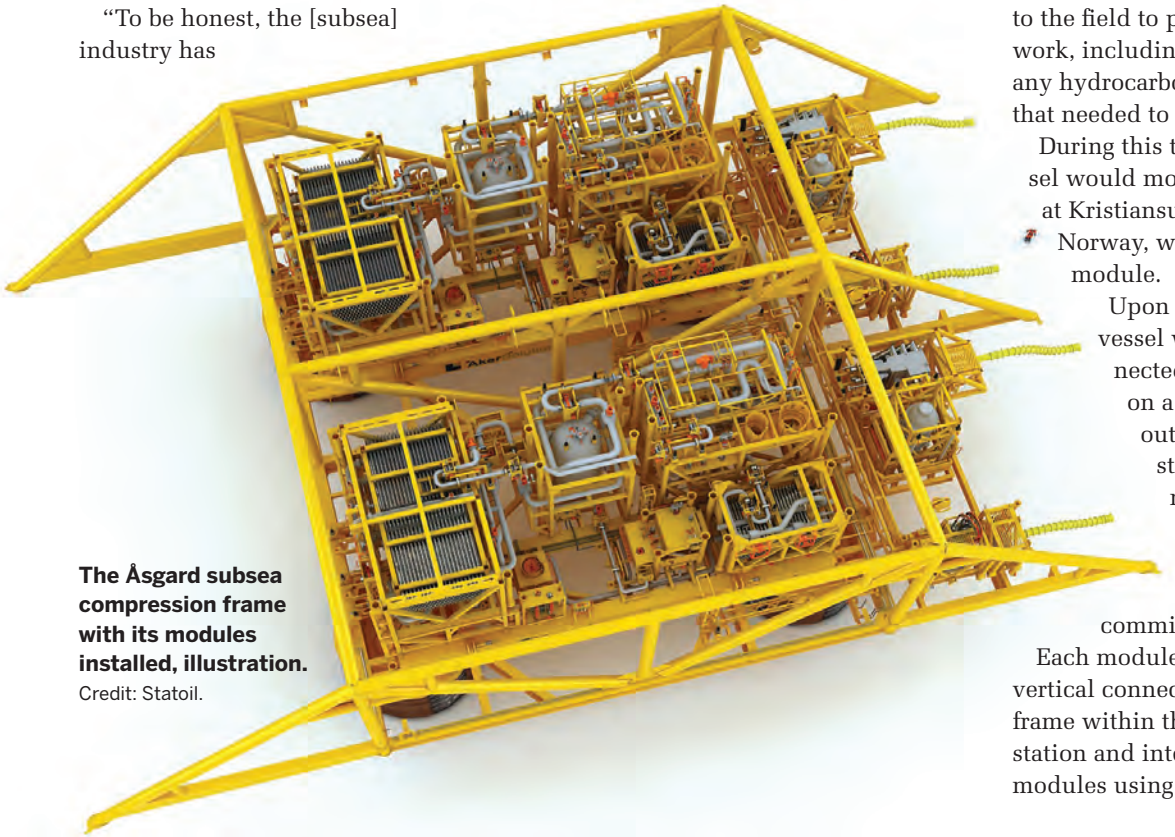
However, Statoil, which has plans to have a complete subsea factory by 2020, says that any new vessel would still work in tandem with a standard IMR vessel to ensure fast turnaround of a module replacement.

First, an IMR vessel would mobilize to the field to perform preparatory work, including displacing with MEG, any hydrocarbons within the module that needed to be removed.

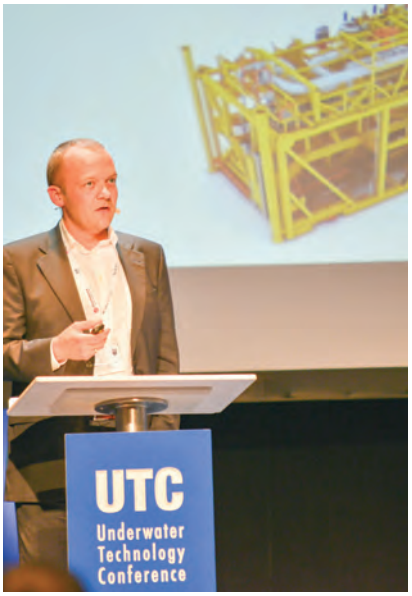
During this time, the SPI vessel would mobilize from a base at Kristiansund, on the coast of Norway, with a replacement module.

Upon arrival in field, the SPI vessel will lift out the disconnected module and place it on a subsea "parking frame," outside the compression station. The replacement module would then be installed into its slot in the compression station and commissioned.

Each module will be fitted using vertical connections to a cassette base frame within the subsea compression station and interconnected to other modules using sliding spools.



The Åsgard subsea compression frame with its modules installed, illustration.
Credit: Statoil.



Raimund Bjordal, technical lead, subsea processing intervention, Statoil. Credit: UTC2013.

The replacement module would be landed using a water-dampening system and would then be landed out on extended hydraulic cylinders. Final mating of the vertical connections is then performed by retracting cylinders, all controlled using an ROV at a hydraulic power panel.

Once the installation and commissioning is complete, the SPI vessel would recover the module, waiting to be refurbished, up to surface and then transport it back to Kristiansund.

If it is a compressor module, further work would be required before it could be removed, freeing it of hyrdocarbons and residual pressure before it is brought to surface.

The contents of the compression module would be displaced with MEG and then nitrogen, with the displaced MEG removed to the scrubber module. The compression module would then be lifted over to the subsea parking frame, while the new module is lowered into position and commissioned.

Any residual hydrocarbons in the compression module would be diluted with nitrogen and then flared off via a hose connected to the SPI vessel process system topside, until the contents no longer pose an explosion risk. During recovery through the water column, pressure in the compressor would be balanced by means of check valves, enabling the compressor to be at an ambient pressure before it is lifted on deck.

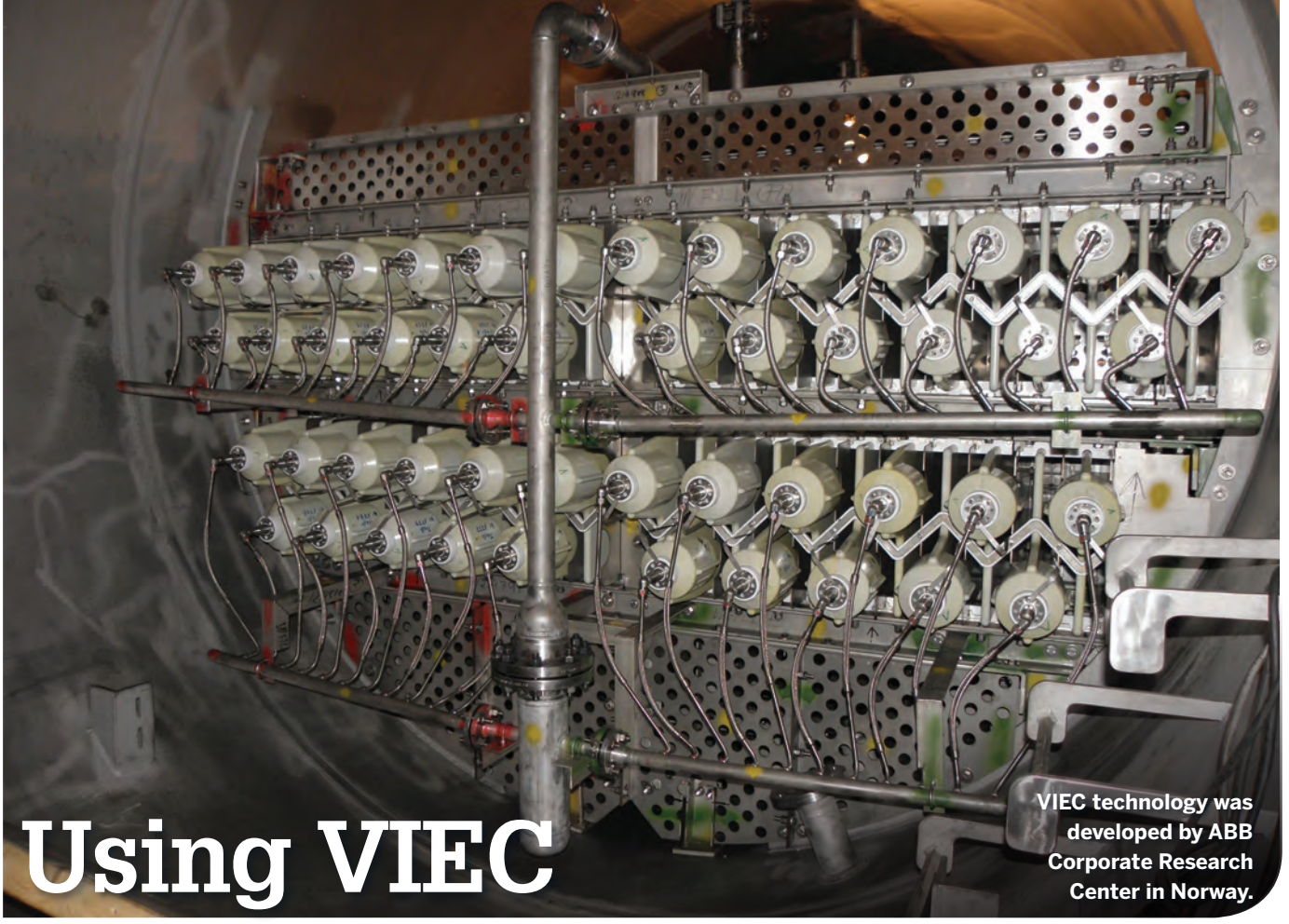
"Results of feasibility studies we've done show it is possible to do this from monohul vessels," Bjordal says.

If such a vessel was also used by Shell on Ormen Lange, project economics would improve further. Statoil and Shell say they are "cooperating" on the issue, but it is not yet clear what the solution will be.

Shell, as Ormen Lange operator, has not yet concluded on the future infield compression solution. In addition to subsea compression, a conventional tension leg platform is also an alternative for future infield compression.

In case the subsea solution is chosen for Ormen Lange, Owe says that Shell would need a new vessel in 2020, at the earliest.

Bjordal concludes: "We think having a new service for subsea process intervention is a key enabler to make this Statoil subsea factory a success in the future." OE



VIEC technology was developed by ABB Corporate Research Center in Norway.

Using VIEC to enhance oil separation

By Meg Chesshyre

Wärtsilä's acquisition of the British-headquartered, global engineering company Hamworthy early in 2012 has added a portfolio of high technology products and systems to the Finnish power solutions company's offering including vessel internal electrostatic coalescer (VIEC) technology, which improves the efficiency of the separation process, thus enhancing oil recovery. Originally developed by ABB Corporate Research Center in Norway in 1998-2001, VIEC technology is covered by worldwide patents.

Existing fields are maturing and experiencing more water coming out of the reservoirs with less oil, exceeding the design basis for the production equipment in use. Reservoir pressures are dropping, which leads to the installation of pumps and once again causes problems with stable emulsions in the separation process. Future oilfield developments will be more challenging as 50% of the world's remaining oil reserves can be characterized as either heavy or extra-heavy oil.

Traditionally, heavy oils are separated by using huge separator vessels and allowing extra long periods for the water to settle, as well as adding large quantities of chemicals and heating the crude oil to temperatures of up to 150°C. Significant additional operational costs are inevitable. "Improving the efficiency of the separation process by means of VIEC technology can reduce fluid temperatures below 100°C, allow the optimization of separator vessel size and reduce the use of chemicals," says Erik Bjørklund, innovation manager and acting director of separation technology at Wärtsilä. "This not only has a positive effect on capex and opex, but also on levels of CO_2 emissions."

Coalescence of dispersed water in an oil-continuous phase can be greatly enhanced by subjecting the emulsion to high-voltage electric fields. This phenomenon is called electrostatic coalescence. When an emulsion consisting of a polar liquid dispersed in a non-conductive liquid is subjected to electric fields, several physical phenomena cause the droplets to merge. In a VIEC system, two primary effects can be identified. Firstly, an electrical dipole attraction causes droplets to coalesce. Secondly, the electric fields distort and weaken the film, i.e. the surfactant components surrounding the water droplets.

Separation efficiency can usually be influenced by increasing gravity forces, density difference and the diameter of the water droplets or by reducing viscosity. Droplet growth caused by the electric fields therefore leads to a substantial growth in the settling velocity of the dispersed droplets and enhances separation efficiency. As the surfactant components prevent coalescence, proper chemical treatment such as a demulsifier is also needed.

"A VIEC system typically consists of 150–200 electrodes – depending on the size of the separator – forming a cross-sectional wall within the

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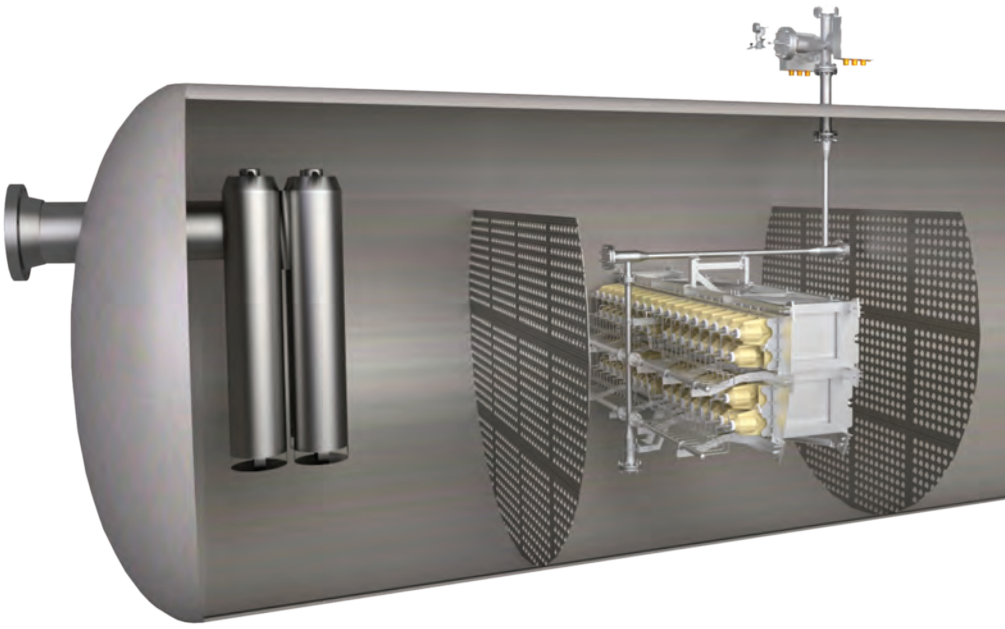
separator which allows the fluid to pass the electrodes and be exposed to the electrical field," Bjørklund says. "Following electrostatic treatment, water quickly settles to the bottom of the separator and is piped to the water treatment system, while the crude oil flows across to the oil section."

Installing VIEC technology has to be planned carefully. The equipment must be a correct fit at the first attempt and the installation process must be performed quickly to reduce downtime. The whole installation also has to be performed through a manhole just 18-24 inches wide. As well as being designed to pass through the manhole, the component parts have to be bolted together inside the separator unit. "To secure safe and on-time installation, Wärtsilä performs a full-scale test installation prior to equipment delivery," Bjørklund says. "While installing a VIEC system inside a separator takes just a few days, additional time is required for depressurizing and cleaning prior to installation, and pressurizing and re-commissioning after the installation is complete."



To deliver the correct VIEC solution for each customer, Wärtsilä analyzes and characterizes the crude oil that it will be handling. "Crude oils are very complicated liquids and are all very different by nature," Bjørklund says. Customers send a 20–100 liter sample of crude to the Wärtsilä laboratory in Norway. Wärtsilä has analyzed more than 80 different crude oils from all of the world's primary crude oil producing zones. In addition to a library of real crude oil samples, this allows Wärtsilä to build up a unique database of knowledge.

Characterization of the crude oil includes determining its dielectric properties, viscosity, density, surface/interface characterization, asphaltene stability and emulsion stability, as well as inorganic/organic solid

A VIEC system consists of 150–200 electrodes forming a cross-sectional wall to treat and separate oil and water.

quantification and residual water quantification.

Following the characterization process, a range of separation tests is performed to verify the effect of a VIEC in combination with different chemicals. Separation testing focuses on retention time in the electrical field, chemical screening, turbulence, shear, recirculation patterns, flow entrainment of small droplets and other dynamic effects.

"As well as verifying the use of electrostatic technology to treat the crude oil, this testing also provides data for oilfield owners and operators, which allows them to optimize and remove bottlenecks from the overall separation process. This can result in smaller separator vessels, reduced processing temperatures and reduced dosing with chemicals."

Traditional electrostatic coalescer vessels are equipped with uninsulated high voltage electrodes that cannot be exposed to gas, and the more than 10-15% water remaining in the oil. A significant advance has been the development of an electrostatic device with insulated electrodes, making it possible to handle 100% water as well as any gas present. This allows such devices to be installed into upstream production separators.

"We have successfully delivered and installed vessel internal electrostatic coalescers into more than 30 test and production separators treating crude oils ranging from API 12–50°, with an equal split between retrofits and new-builds, and covering most of the major national and international oil companies," Bjørklund says.

The newest generation VIEC technology has been delivered to the FPSO *OSX-1*, the first floating production, storage and offloading unit in OSX's fleet, which is working for OGX in the Campos basin off Brazil. The system has been installed in both the first stage separator and the test separator in order to improve processing of the heavy crude oil on the Waimea field in the Campos basin. An installation at Qatar Petroleum's onshore Dukhan field has led to a reduction of the basic sediment and water levels from about 5% to 0.2%, well below the target level of 2%. Salt content in the crude oil was also reduced by up to 90%.

"We are pleased to provide advanced technologies resulting from more than a decade of continuous R&D combined with operational experience from a number of deliveries since 2003 to improve oil and water separation performance for our customers," Bjørklund says. "We believe this technology will support future developments of heavy oil fields." OE

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Monitoring is only the beginning

Sophisticated monitoring systems on floating production systems can provide real time information for operational support and to improve performance, but a holistic approach is needed to be fully beneficial. Louise Ledgard, head of oil and gas business development, BMT Group explains.

Recent severe storms in the UK North Sea have resulted in a number of floating production, storage and offloading vessels (FPSOs) being shut down in order to assess and repair the damage caused.

Notwithstanding the possible safety implications for operations crew, oil and gas production companies are facing weeks, if not months, without a critical asset, which in turn is having a significant impact on future production.

The design and operation of an FPSO in remote locations requires detailed information on the structural response of the vessel within the local environment offshore.

Monitoring of critical components including the risers, hull, and mooring lines simultaneously with the local environmental forcing of waves, wind, and currents at the site location provides a valuable insight into the performance and possible extension of the integrity life of the asset.

As new technology is introduced, riser design becomes more sophisticated and extension of design life is required, it becomes increasingly important to monitor an asset's performance to assist with operational decisions, forensic investigation of marine incidents and the evaluation of design codes.

Over the last few years, an increase in the number of offshore incidents related to FPSOs in the North Sea during extreme storm conditions has resulted in focused attention on the verification of design codes and a review of inspection procedures.

With an average mooring failure projected at 8.8 years for an FPSO in the North Sea and the consequential damage this could have on the riser, a number of Joint Industry Partnership (JIP) initiatives have concluded that the management and audit of the FPSO integrity is required.

As an attractive and flexible option, which eliminates the need to lay expensive long-distance pipelines, the number of FPSOs being put into service in remote locations is rising. As such, the complexities of understanding the performance of the vessel in given sea-states and the interaction of the FPSO with the subsea infrastructure, becomes imperative.

Marine monitoring systems have primarily been used to provide real-time information for operational support during production with typical examples of its use being: vessel position (particularly in storm conditions); information on the metocean

conditions during operation; production riser tension, buoyancy and stroke, and mooring line tension for failure detection.

Furthermore, monitoring systems provide information to verify the design of the asset and provide input into fatigue calculations for mooring lines and risers. Currently, finite mathematical modelling is carried out when designing the riser configuration for the FPSO, but what is often lacking is the robust data to validate the actual local environmental conditions.

Feeding this data into the design process can help to validate the accuracy of the modelling tools being used and reduce uncertainty.

The standard sensors and parameters that should be measured within the system include:

Meteorological—the monitoring of the meteorological conditions offshore is critical to ensuring the safe operation of the asset. In 1981, the Civil Aviation Authority (CAA) and the Helideck Certification Agency (HCA) introduced the CAP 437 standard for the UK Continental Shelf and currently recommends that meteorological parameters and motion of the helideck are measured for an FPSO. Such parameters provide critical operational information which is sent back to shore so that companies planning any crew changes or helicopter operations are fully aware of the weather status on the vessel before dispatch. Safety of employees is of the upmost importance; therefore companies want to ensure safe take-off and landing conditions.

Wave monitoring—wave-induced loads are the main source of fatigue for FPSO design, and wave height is a significant factor to consider for the design of the risers, as well as assessment of mooring fatigue life and hull integrity. Recording the extreme events in storm conditions also provides valuable input to the marine forensic investigation of any offshore incident.

Ocean current—Surface currents can impact on any offloading operations from the FPSO to the shuttle tankers and influence the response of the risers and moorings, resulting in fatigue loads.

Position and attitude—measurement of the position of the FPSO is essential in storm periods to understand the vessel response to environmental forcing and the coupling of the resultant fatigue on risers and mooring lines. The position of the vessel is also critical in the assessment of any marine incident.

Riser monitoring—a detailed understanding of the environmental forcing to the FPSO combined with the riser response can aid the design process and provide the input to fatigue calculations.

Hull monitoring—stress-induced in the deck and hull of an FPSO can be monitored using a series of long base strain gauges positioned in strategic locations on the deck and flare tower. In addition, pressure sensors installed in the hull provide information on the vertical acceleration of the FPSO.

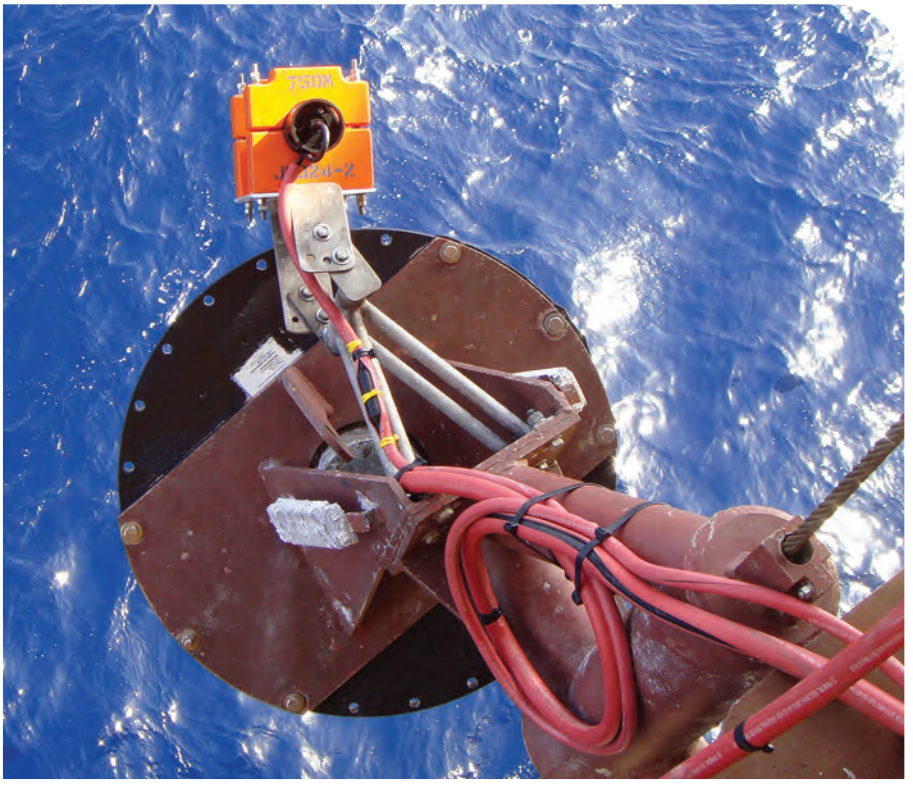
Mooring line—monitoring the mooring line is challenging and there is a scarcity of long term in-situ observed data sets for mooring line tension. For forensic engineering and validation of design codes, it is essential that mooring line tension is collected simultaneously with metocean parameters on a common time base.

Each of the components mentioned above are likely to involve a number of third party suppliers, therefore the challenge that oil and gas majors are faced with is ensuring they all integrate into one effective monitoring system, to provide a holistic approach and support the assets' integrity management program.

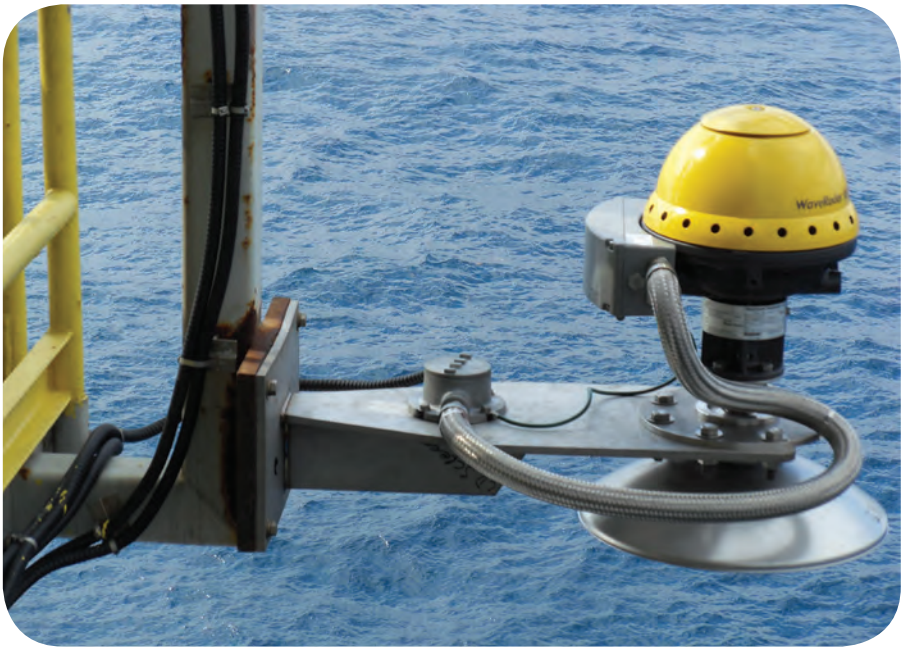
By carefully setting up the sensor clocks and sampling frequency during the installation of sensors at strategic locations on the FPSO, companies can use the resultant data set to effectively study the coupled response of the vessel with the environmental and resultant dynamic loading on the risers and mooring lines to study fatigue.

Monitoring of all the different parameters within this common time base can also assist with forensic investigations of marine incidents. For example, companies want to be able to match the time the mooring line broke with the highest wave that hit the FPSO.

If the clocks on the mooring sensor are different to that of the wave sensor, forensic engineers will not necessarily marry the two together. Instead of working in isolation, the different parameters must be fully integrated to allow the root cause of the incident to



An acoustic doppler current profiler being deployed offshore.



An air gap sensor, deployed to measure wave height from an FPSO.

be clearly identified.

Significant advances in technology over the last decade have meant that oil and gas majors can monitor the effect the local environmental conditions have on their critical infrastructure offshore.

Sophisticated sensors on board an FPSO can provide real time information for operational support and provide valuable input into studies on the performance of the FPSO in varying sea states. However, to be fully effective oil and gas companies must look at the monitoring of their critical assets holistically with the end user taking an active role in the planning and implementation of an integrated marine monitoring system.

It is vital that data is archived and stored in a common portal to allow engineers and operational teams to make the most of this valuable information. Only then can they feel confident that the system is indeed fit for purpose, and the risks of lost production due to repair or worse, a lengthy shut-down, are minimized. OE

Louise Ledgard *holds a PhD in materials engineering and design from the University of Liverpool, a degree in applied physics and a masters in business administration. She has spent more than 15 years' working in the offshore oil and gas sector.*

Fig. 1. High molecular weight polyethylene (HMPE) ropes are replacing wire ropes in many applications.

HMPE rope technology enables deeper and safer operations

By Justin Gilmore, Samson Rope Technologies

The offshore oil and gas industry has changed tremendously over the last several years. Moving into deeper waters has created challenges in operations that would be considered commonplace in shallow water projects. Deeper water has not only made tasks more complicated, but also more costly. Becoming more efficient in deep water operations leads to less risk and higher profits.

Traditionally, subsea contractors have looked to wire rope as the strength member for many lowering and lifting applications. Wire rope has a long and successful history of use in winches, cranes, and rigging. Although wire rope has a proven track record, it does have its limitations. When performing deepwater operations, weight can be an issue. Wire rope is very heavy, which means that winch and crane wires will significantly reduce payload capacity of the winch or crane as the depth increases. Often, the winch or crane can only be used at a fraction of its designed load rating, due to the fact that much of load is the wire rope itself.

Other issues with wire rope are its "inflexibility" and maintenance requirements. A wire rope, especially in a large diameter, can be very cumbersome to handle for a diver or ROV. It also can create problems in tight areas. This is true for surface jobs as well. Handling of wire rope causes numerous injuries every year. Maintaining wire ropes can be costly and creates environmental issues that have to be dealt with. Lubricants can be messy, leading to unsafe work areas; this negative environmental impact must be considered.

Synthetic rope technology has evolved in recent years and is replacing wire rope in many applications where weight and/or handling issues prevent wire rope from being used.

Synthetic fiber ropes have the same strength as similarly-sized, steel-wire ropes. The largest advantage, however, is the difference in weight. Synthetic ropes weigh 80-85% less, depending on the material used. Some synthetic materials are buoyant, which means they add no weight to the payload regardless of depth.

Fiber ropes require no maintenance, are much more flexible, easier to handle, and are much safer. Most synthetic materials are resistant to common chemicals and have very good ultraviolet resistance. Fiber ropes can also be treated with various coatings to improve certain characteristics.

Two projects demonstrate how synthetic rope technology has replaced steel-wire rope, creating a safer and more efficient operation. Both projects also show how synthetic HMPE (high molecular weight polyethylene) ropes were used to solve design problems.

Perdido Spar

When Shell was designing the Perdido Spar platform's subsea asset deployment and retrieval system, it faced a problem: at water depths over 8,000ft, a traditional wire-rope drum winch system would be too heavy for the platform on which it was to rest. A new winch/rope system was needed.

Shell chose Samson's Quantum-12 synthetic rope on a Logan Industries traction winch to solve the problem. It marked the first time Shell had used an HMPE rope system on a spar platform and the first time Samson's rope had been used in this type of application.

The Perdido Spar, operated by Shell on behalf of partners BP and Chevron, is part of the world's deepest oil production facility. It is the most remote producing platform in the Gulf of Mexico, almost 220mi. off Texas, and the only development in the region to use subsea separation and boosting equipment. The development features 22 wells and 13 well tie-backs, which must be changed out and serviced at regular intervals.

Rather than deploying offshore service vessels to the remote development

at great expense, the spar's design includes a winch system that allows the platform to service the subsea equipment. Operating in nearly 9,000ft of water, while handling payloads of up to 90,000lb, is a challenge. Compounding the problem, the spar's design places the winch on a cantilevered deck (a smaller deck extending out from the main platform), imposing significant weight restrictions.

A traditional steel-wire rope of this length would be prohibitively heavy. Weighing 81,750lb, it would require double the lifting capacity of the winch. This would in turn increase the size of the winch and require significant structural modifications to be made to the spar.

Another, and more significant, issue was the winch capacity. When using steel-wire rope, significant winch capacity is consumed by the wire weight. The deeper the job, the longer steel-wire rope is needed, and the less capacity the winch system will have. This means that the winch would have to be larger to accommodate the needed pay load at depth.

A synthetic rope is buoyant; therefore, it adds no weight to the payload, regardless of length. The weight does not change (significantly) regardless of depth, Figure 2.

Resolution

To solve the problem, Shell solicited possible solutions from their winch and cordage suppliers. After reviewing several proposals, Shell decided a synthetic winch line offered many advantages and would require minimal deck space.

Shell turned to Samson for high-strength, lightweight synthetics and to Logan Industries for a simple, traction-style winch design. This combination met the weight and footprint restrictions of the cantilevered deck and was capable of performing the subsea operations, Figure 3.

Samson provided 9,200 ft of 2-1/2in. -diameter, Quantum-12 HMPE rope. Weighing 85% less than a wire rope of similar size and length, this greatly reduced the deck weight needed. Samson also worked closely with Logan Industries, assisting the design engineers in creating a smaller, lighter winch system specific to the rope's characteristics.

The rope provides the same strength as similarly sized wire rope. It is made with Samson's patented DPX fiber technology for superior abrasion and cut resistance with a higher coefficient of friction (COF) than other HMPE ropes. The higher friction coefficient is an advantage over other HMPE ropes, allowing it to be used on a traction system. Typically, the COF of steel ropes ranges from 0.05 - 0.08. The DPX technology increases this to 0.1 - 0.15, minimizing "slip" and damage.

Synthetics also offer superior bend fatigue properties than steel-wire rope at smaller bend ratios. This feature allowed Logan to design the winch system with a smaller diameter traction head, resulting in significant weight reduction.

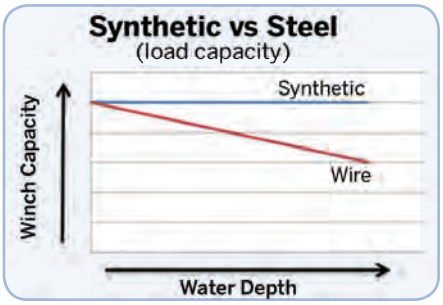
Since there was no heave compensation needed, cyclic bend fatigue was not a concern. Another advantage that synthetic ropes have is a natural damping effect that helps minimize package motions (vs. steel). Steel-wire rope acts like a spring, transferring vessel motions to the package. A synthetic rope has hysteresis, which provides energy dissipation that minimizes transferred motions. Figure 4 shows the "looping" effect as a synthetic rope is cycled.

To date, the system has performed 250+ operations without any issues. The original rope is still in service.

Jubilee field

The Jubilee field off Ghana, West Africa, is estimated to hold 1.2Tcf of gas and 1.8 billion bbl recoverable crude oil reserves, making it

Fig. 2. Buoyant, synthetic rope adds no weight to the winch payload, regardless of rope length or operational depth.



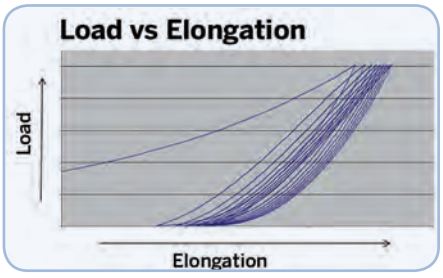


Fig. 4. Synthetic rope's "looping" effect shows the positive effect of hysteresis, which dissipates energy to minimize transferred motions.

Fig. 3. Lightweight, synthetic rope allowed use of a simple, traction-style winch to meet weight and space restrictions on a cantilevered deck.

Fig. 5. Jubilee field used synthetic rope for anchor-chain tensioning and riser pull-ins.

the second largest field in the world. First oil was produced in December 2010, after risers and umbilicals were installed from the seabed at depths of 900-1700m to the FPSO *Kwame Nkrumah*, which successfully completed the fastest ever, full-scale, deepwater development. Samson's Turbo-EPX synthetic rope was instrumental in the 11-riser installation, but not before AmSteel-Blue first assisted with mooring the FPSO.

Sofec was in charge of the design and installation of the turret for the Jubilee field development. Included in the turret design was a winch system that would be used for two projects: anchor-chain tensioning and riser pull-ins, Figure 5.

The company was concerned about limited room on the FPSO deck. The most efficient solution would be to use a small winch for the riser pull-in system. A synthetic rope solution would simplify the winch design and allow a smaller drum diameter to be used. Synthetic rope would also allow a size reduction of the hydraulic power unit and the deck load.

Sofec contacted SWOS, Samson's master fabricating distributor in Houston, Texas, to discuss a synthetic rope solution for the pull-in lines. Samson synthetic ropes for offshore applications are made with Dyneema fiber, which brings high-performance characteristics such as high strength, light weight, abrasion resistance, and neutral buoyancy to innovative rope constructions and coatings. The light weight and "flexibility" of the synthetic ropes would make handling much easier in a small space. The weight would be 1/7 (14%) that of steel, allowing the ropes to be handled by hand.

Technip was responsible for the risers and had some abrasion concerns as the synthetic ropes were being pulled through the riser tubes, Figure 6. While SOFEC was confident that the ropes would work well in both applications, the riser installation engineers at Technip were not so sure.

Because of the neutral buoyancy of the synthetic ropes, Technip also was concerned that the rope would catch in construction vessel propellers, which would approach very close to the FPSO when the risers were transferred. Samson put application engineers to work developing a solution.

SWOS and Samson engineers worked closely with SOFEC to understand all of the nuances of this project and equipment. The engineers determined that the best combination of equipment would be a split-drum winch with a working load limit of 350 tons, loaded with 350m of 5 5/8in.-diameter Turbo-EPX HMPE rope, which has a minimum breaking strength of 875 tons.

This rope has a jacketed construction with a 12-strand core strength member made with high-strength, low-stretch Dyneema fiber. The jacket is made with polyester that grips the winch and hardware, and is abrasion resistant. To ensure that the rope would sink rapidly enough to avoid catching in tugboat propellers, a segmented lead-line was added to the center of the 12-strand braided core. The addition of the lead allowed the rope to slowly sink out of the way of the propellers. The specific gravity increases from 1.01 to 1.12.

Once the customization and manufacture were complete, the line underwent extreme scrutiny. It was initially break tested, witnessed by the American Bureau of Shipping (ABS). Then Technip, the project managers for the installation, commissioned a study by Bureau Veritas (BV), who found the rope to be more than adequate, with a safety factor of 3:1.

With these certifying agencies' approval, Samson manufactured three lines for the Jubilee riser pull-in job. Sofec planned to use one of the three lines for the anchor chain pull-in and tensioning line. This left one for the riser installation, and one as a backup.

After further consideration of the anchor-chain pull-in job, Sofec realized that the significant 5 5/8in.-diameter of the rope would cause the line to bear against the cast-steel sidewalls of the chain stopper's internal cavity. Again, Sofec contacted SWOS, who recommended a smaller diameter rope of AmSteel material to pull-in the mooring chains.

SWOS provided 738ft of 3¼in.-diameter rope with a soft eye on each end. This rope is able to handle a working load limit of 100 metric tons (mt) with a 400mt minimum breaking strength, equaling a 4:1 safety factor.

Results

In a typical FPSO mooring application, both wire and synthetic ropes are used on a split-drum winch; however, the AmSteel-Blue rope worked in place of both. The rope's easy handling and change-out allowed engineers to simplify the winch-drum design, and provided flexibility for the nine-anchor-chain installation

Fig. 6. Abrasion concerns were overcome by making the rope jacket from abrasion-resistant polyester.

and tensioning. The rope took quite a beating, but finished the job without failure. Once the *Kwame Nkrumah* was secured in place, the Turbo-EPX rope was reinstalled on the winch and ready to pull in the risers.

Only one of the three Turbo-EPX lines was used to pull the 11 risers. According to one Technip installation engineer, the rope was still in good shape after the job was complete.

These examples demonstrate how synthetic ropes can replace steel-wire ropes, creating more efficient and safer operations. One of the barriers to using synthetics can be initial cost. Synthetic ropes can be 2-4 times more expensive than wire rope. Therefore, it is important to look at total cost of ownership and equipment cost. In most cases, when the total costs are compared, using synthetic ropes can be more cost effective. More importantly, synthetic ropes are safer.

Steel-wire rope has a home in many applications, and is still a tried and true workhorse. Synthetic ropes, however, should be considered when weight and handling become an issue. This is especially true for larger diameter ropes. In many cases, the user will find significant value in using high performance synthetics. OE

Justin Gilmore *is technical sales manager for the Offshore Business Unit of Samson and has over 23 years in the synthetic rope industry. He has an extensive background in synthetic rope design, manufacturing processes, quality programs, and application engineering with many field-related publications and patents.*

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Mexico's deep water

Pemex Exploration and Production has recently drilled three successful wells testing the deepwater Perdido Fold Belt, but questions remain about the NOC's timing to develop the offshore discoveries.

By Nina Rach

Mexico's earliest deepwater exploration was in 2003, when the Chuktah-201 well was completed in water 513m deep, followed by the Nab-1 well in 2004 at a water depth of 681m. Chuktah-201 was a dry hole, and Nab-1 had non-commercial quantities of oil, but finding oil in deep water has become a priority for Pemex.

The company has acquired 90,000 sq km of offshore 3D seismic data from 2002-2011. There are currently five semisubmersibles at work in deep water off Mexico, among the 80 offshore drilling rigs.

Reserves, budget

In 2006, Pemex drilled the Lakach-1 well, a large natural gas discovery with 2P reserves of 0.9 Tcf. Pemex says reserves could be as large as 1.4 Tcf, including satellite fields: Ahawbil, Labay, Piklis, and Kuyah. Pemex estimates 3P reserves at Piklis field, discovered in May 2011, at 0.8 Bcf.

Between 2007 and 2010, Pemex spent about US$1.8 billion on deepwater exploration, representing about 24% of the overall exploration budget. The deepwater exploration budget in 2011 was $1.14 billion, dropping to $1.07 billion in 2012.

The 2012-2013 work includes three deepwater wells in the Perdido basin. This area is about 200 miles (320 km) off the Texas coast and stretches across the US-Mexican maritime border.

Deepwater rigs

Mexico City-based Industrial Perforadora de Campeche SA (IPC) has been working in Mexico's oil industry since 1985 and runs its maritime operations from two shore bases: one in Veracruz and the other in the port of Laguna Azul, Ciudad del Carmen, Campeche.

In June 2007, IPC signed a 5-year contract with Pemex E&P for a semisubmersible drilling unit, which began running in late 2010. In July 2007, IPC commissioned Daewoo Shipbuilding and Marine Engineering Co. (DSME) to build a Gotaverken GVA 7500-design semisub capable of drilling in water to 10,000 ft (3,048 m) and 40,000ft TD. This sixth generation MODU, *Bicentenario*, was delivered in February 2010 and arrived in Mexico in May 2011.

In August 2008, IPC contracted with DSME to build a sister ship, *La Muralla IV*, delivered in October 2012. Grupo R Perforación Marina operates *La Muralla IV* and began drilling the Piklis-1DL well in water 6053ft (1783m) deep, on 9 April 2013.

Concurrently, Grupo R launched *Nautilus IV*, the first phase of its new ROV initiative, on the *La Muralla IV.*

A sister company of IPC, Grupo R Exploración Marina, S.A. (GREMSA), operates a third semisub, *Centenario GR*. This MODU is Friede & Goldman ExD Millennium design, capable of reaching a total depth of 40,000 ft. It was delivered from the Jurong shipyard in Singapore in 2010 and is working under a 5-year drilling services contract for Pemex E&P that started in September 2010. GREMSA is the first wholly-Mexican company to provide deepwater drilling services in Mexico.

Two other semisubs currently working off Mexico are Diamond Offshore Drilling Inc.'s Ocean Yorktown, third-generation MODU capable of drilling in 2850-ft water depth; and Seadrill Ltd.'s West Pegasus, a sixth-generation MODU capable of drilling in 10,000-ft water.

Drilling

Pemex drilled the Trión-1 well, 180km off the coast of Tamaulipas, the first of three wells in Mexico's Perdido Fold Belt. The well made a commercial discovery of light crude, announced in August 2012. Mexican President

Felipe Calderón Hinojosa said it could produce "4 to 10 billion bbl of oil" and allow Mexico to "increase oil production in the medium and long term."

In October 2012, Pemex reported discovering light oil in the Supremus-1 well, the second Perdido well, in 9515ft (2890m) water depth. Calderon announced that the field probably holds between 75 and 125 million bbl of oil.

After drilling the Trion-1 and Supremus-1 discoveries, Pemex estimated 10 billion bbl of untapped crude oil in the Mexican sector of Perdido.

The third Perdido well was the Maximino-1 wildcat, in the deepest water yet, 9570ft (2933m). It was described in 2011 as "the jewel in the crown of our deepwater projects" by Jose Antonio Escalera, deputy director for technical exploration at Pemex.

On 16 May 2013, Pemex announced that they were testing light crude in the Maximino well.

Pemex E&P director Carlos Morales Gil said the company is considering a standalone spar or FPSO to develop Trión and other discoveries in deep water. In June 2013, Pemex awarded an $84 million contract to GE for subsea wellheads. OE

Colombia's promising future

The next few years could see major investments in Colombian waters and last year's bid round has independents, NOCs, and majors heading to the country's Caribbean shores.

By Audrey Leon

Colombia is South America's fourth largest oil producer with 2 billion barrels of proved oil reserves, according to the US Energy Information Administration (EIA). New regulatory reforms and a close relationship with the US government seem reason enough to make investing in Colombia an attractive bet.

The country's national oil company Ecopetrol, while 90% owned by the government, is also open to private investment and partnerships with foreign companies. Colombia has invested in security over the last few years to protect its energy infrastructure, but the country is still at odds with its longest-running rebel insurgency, the FARC (Revolutionary Armed Forces of Colombia). A cease-fire with the group ended earlier this year and attacks on pipeline infrastructure have spiked; the Cano Limon oil pipeline was bombed back in February.

Despite those woes, companies remain enchanted by Colombia's potential. In 2011, Marcos Mozetic, Repsol Exploration Managing Director, told investors that the country is one of the places where they don't consider the political boundaries.

"We look at the play – that is why we went to Colombia – and we acquired interest in two blocks operated by Petrobas and Ecopetrol as a partner; and we are trying to do more. It is a play that most probably will need more resources in the future and we will try to be active in other places in the Caribbean, too," he said.

Repsol has interest in three offshore blocks in Colombia: Tayrona (near the producing Chuchupa field), RC-11, and RC-12.

Onshore exploration and production is still king in Colombia. During the country's last bid round in 2012, Colombia's Agencia Nacional de Hidrocarburos (ANH) made 113 blocks available, with only 11 of them located offshore.

Orlando Cabrales Segovia, President of ANH, told James Burkhard, vice president and head of oil market research at IHS, that the government had made a concerted effort to spotlight unconventionals, with 31 blocks having significant opportunities in shale gas.

However, of the 11 blocks that were offered, six were awarded when the round concluded in December 2012. Of those 11, five are considered new frontier basins.

The highest bidders on the offshore blocks were Houston-based Anadarko Petroleum, Colombia's national oil company Ecopetrol, India's ONGC Videsh Ltd., and Shell.

Anadarko Colombia Co. will operate one block in the Colombia (COL) basin with 100% interest. Anadarko took 50% interest in two additional offshore blocks in partnership with Ecopetrol, in the Urabá (URA) and Colombia basins.

OGNC's block lies in the Guajira (GUA) offshore basin, while Shell Exploration and Production Colombia GMBH snatched up one block in the Colombia basin.

Cabrales Segovia told IHS that Colombia's oil and gas industry is healthy, with seismic programs steadily increasing over last 5-6 years. Exploratory wells have also increased to 126 in 2011 from only 20 in 2004, and about 150 wells in 2012.

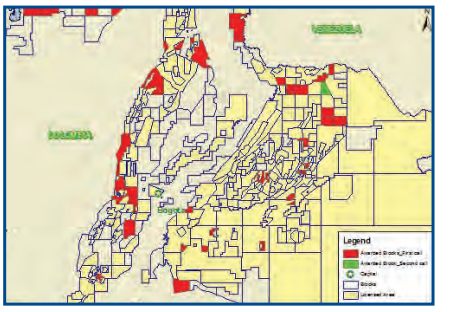
Exploration

Including new licenses won at the end of 2012, Anadarko has six blocks off Colombia's Caribbean coast, totaling eight million acres. Its territory includes 100% working interest in Block COL 2, and 50% interest in blocks COL 5, Fuerte Norte, Fuerte Sur, Purple Angel, and URA 4, according to the company's 4Q 2012 report.

Anadarko plans to conduct 2D and 3D seismic surveys this year, and has hired France's CGGVeritas to acquire and process a 5,500sq-km seismic survey over portions of the six blocks. Work will begin 3Q 2013 with CGGVeritas using the CGG Viking for the program. The survey is scheduled to take four months to complete; the data will be processed in Houston.

Shell is following a similar plan for its deepwater COL-3 block, which spans 5000sq km. The company will conduct seismic surveys before it commits to a drilling program. The block is southwest of Shell's GUA-3 block, which it licensed in 2011.

The Ecopetrol and Talisman Energy joint venture, Equion Energia, began drilling off Colombia last year, encountering dry gas at the Mapale-1 well in block RC5 last November. Mapale-1 was the first offshore well drilled in



Open Round Colombia 2012.

Colombia since 2008. Equion Energia operates the block, which it won in 2007, with 40.56% stake. Ecopetrol holds a separate 32% interest in the block, with the remainder controlled by Brazil's Petrobras (27.44%).

Production

The shallow water Chuchupa field is the largest – and only producing offshore – natural gas field in Colombia, located on the northwestern tip of the Guajira peninsula.

Chuchupa is a dry gas field that was originally discovered in 1973 and brought into production four years later. Located in the offshore Guajira basin, it is currently operated by Chevron in partnership with Ecopetrol. The field produces 80% of Colombia's natural gas, which is piped to both central and northern Colombia, and western Venezuela.

In 2006, Chevron began studying ways to counter reservoir depressurization in the field, settling on artificial lift technology to extend the field's life into 2030. In 2012, net production from Chuchupa averaged 216MMcf/d. Chevron is considering installing additional compression facilities this year.

FLRSU on track

Canada-based, but Colombian-focused, explorer Pacific Rubiales Energy announced last month that its LNG export project is on track to begin 4Q 2014. The planned facility is a first-ever, floating liquefaction, re-gasification, and storage unit (FLRSU) to operate off Colombia's Caribbean coast (OE, July 2012).

Exmar NV was contracted to build, operate, and maintain the FLRSU, which will serve the onshore La Creciente field in Colombia's lower Magdalena Valley basin for 15 years. The FLRSU is currently under construction at Wison Offshore and Marine's fabrication yard in Nantong, China.

"The company has actively invested in pipelines, ports, and other infrastructure facilities over the past five years, allowing it to manage the pace of its production growth and capture additional value. The company is planning to spin out a portion of these assets, keeping operational control, to create additional value for shareholders," said Pacific Rubiales CEO Ronald Pantin.

The FLRSU can convert 69.5MMscf/d of natural gas into LNG, and can temporarily store up to 14,000cu m.

Once completed, the FLRSU will be able to convert 69.5 MMcf/d of natural gas from the field into LNG. The barge, which will measure 140m x 32m x 18m, and will be able to store 14,000cu m in onboard tanks. The processing unit will be moored to a jetty in 15m waterdepth. Topsides equipment will weigh about 5000t. The liquefaction plant will be built by Black and Veatch with the. total cost estimated at US$300 million. OE

A technology-fueled future

***The Next 50 Years* is the strap-line of this year's SPE Offshore Europe—underpinning those five decades will be technology, says BP's North Sea regional president. Elaine Maslin reports.**

This year SPE Offshore Europe is celebrating its 40th anniversary by looking forward to a prospect few in the early days of the North Sea's offshore industry would have predicted.

More than four decades after the first oil was produced from the basin, the industry event is looking forward to *The Next 50 Years*, of both production and the supply chain.

Key to the past 40 years, and even more so for the next five decades, is the development and use of technology.

The challenges facing the industry in this mature basin are rising costs and declining production rates.

According to industry body Oil & Gas UK, North Sea operational expenditure rose 10% for the second year running in 2012, to £7.7billion, with a further rise of £800million in 2013.

The increases are being driven by general pressure on costs and increased spending on asset integrity, as installations near or pass the end of their design lives.

Production rates have dropped sharply, last year falling 18%, on the UK Continental Shelf.

Ensuring the long term future of the North Sea, in the UK and Norway, will require technology and collaboration, says BP North Sea regional president Trevor Garlick, who is chairing a keynote session during Offshore Europe.

The session, *The Technology Imperative – collaborating today to realize the next 50 years of North Sea potential*, will look at the role technology has played in the development of the North Sea to date, and the role it will play in accessing and recovering the remaining reserves in the future.

"The big challenge for the industry is to arrest the decline we have seen," Garlick says. "One of the ways we can do this is to recover more from our assets. We estimate average recovery rates from North Sea reservoirs to be around 40%, meaning we leave more in the ground than we recover; I want this to change. Technology has a vital role in helping ensure we do this."

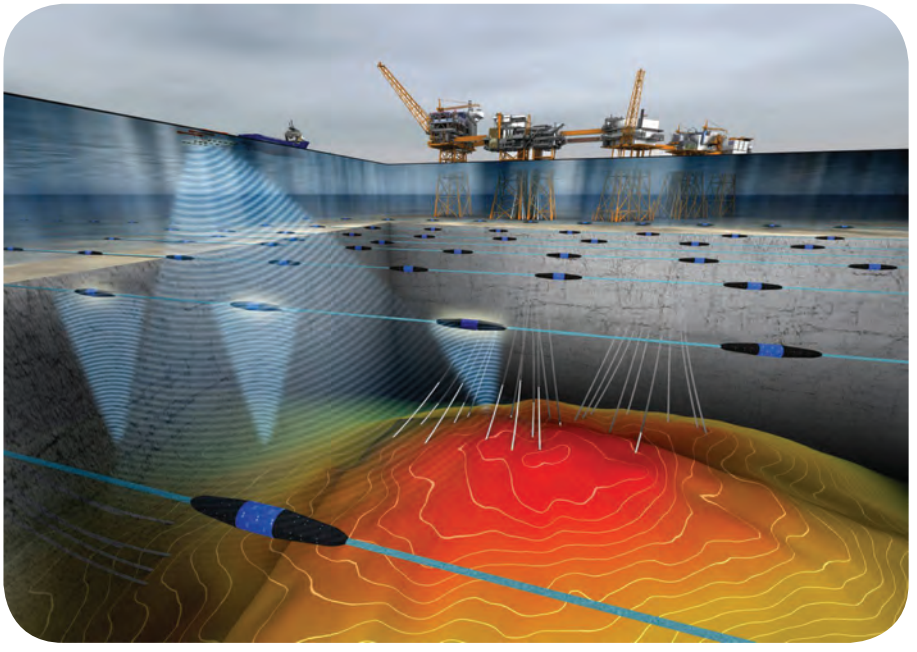
BP North Sea is focusing on developing ways to drill and complete wells at a lower cost, improving plant reliability and asset integrity and enhanced oil recovery.

The UK industry as a whole has similar goals. According to a survey last year by the country's government Department of Energy and Climate Change (DECC), the main areas the industry wants to focus on are: seismic and reservoir characterization; enhanced oil recovery (EOR)/production optimization; asset integrity/life extension and decommissioning; and well construction and drilling.

"A key priority is to obtain better images of the reservoir," Garlick says. "Our own seismic technology strategy is three-fold."

BP is using wide azimuth high density OBC (ocean bottom cable) acquisition to identify additional targets in hub areas, including on Farragon,

BP has developed life of field 4D seismic, or permanent seismic installation, featuring 120km of permanently trenched GERI ocean bottom cables on its Valhall field in the Norwegian North Sea.



Clair, Magnus and ETAP, all in the UK North Sea.

4D seismic reservoir monitoring, through repeat towed-streamer acquisitions or permanent seabed systems, is being used on the Foinaven-Loyal-Schiehallion cluster, west of Shetland, ETAP, and Valhall and Ula, offshore Norway, to help increase recovery.

Making frequent 4D repeat surveys possible at reduced cost, with high data quality and reduced HSE risk, is still a challenge, he says.

"Ideally we would like to have permanent sources developed to have a fully integrated seismic monitoring system on the sea bed," Garlick says. "There are down-hole tools available, but they are not yet proven in a 4D permanent reservoir monitoring context.

"A permanent source would enable us to monitor fluid movement and effects of EOR as and when needed, without having to rely on mobilizing a dedicated source vessel and the operational risk this brings."

Improved imaging helps, but seeing the reservoir better is just the start, Garlick says. "We need to be able to increase the amount we can displace from the rock structure."

BP is working on miscible water/gas (WAG) schemes at Magnus and Ula and will deploy low salinity water flooding on the Clair development. On the Schiehallion redevelopment, BP is planning to deploy polymer flood.

However, Garlick says: "For a mature basin the UK has relatively few EOR schemes either in production or in development."

This is because of the cost of supplying suitable injectant, complexities around retrofitting equipment on existing facilities, and economics—projects providing incremental increases in production but with high up front capital cost outset or expensive operating costs.

Garlick says there could also be improvements in drilling. This year BP installed its longest ever 9 5/8 in. casing string in the UK sector at 6600m long, from the Magnus platform, using ERD (extended reach drilling) technology.

The project involved real-time monitoring of trends to inform decision making; incorporation of lessons learned from offset ERD wells; use of friction reduction technology and increased focus on drilling string components to minimize failure.

Trevor Garlick, BP North Sea regional president.

But there are further opportunities for improvement, in particular in managed pressure drilling; reliable cement evaluation; and subsea BOP reliability, Garlick says.

To achieve it all, collaboration and the use of technology is key, he says.

BP is sponsoring a PhD on how improved paint technologies can protect offshore infrastructure. Last year it announced a US$100million, 10-year partnership with the University of Manchester to improve materials management.

BP chief scientist Professor Ellen Williams, who will be on the keynote session panel, says collaboration with universities will also help to unlock future oil and gas reserves.

Prof Williams' own research background is in the field of nanoscience. One of the last materials she worked on, before joining BP in 2010, was the ultimate thin film, graphene, which at just one atom thick has properties with potential applications in chemistry, coatings and electronics.

She says collaboration with universities is beneficial for both parties. "BP brings much needed funding. But as well as funding, BP brings real-world problems for universities to grapple with, which gives them a window on new directions and new applications in which they can shape their research."

"There is lots of potential to increase the recovery of oil from the UKCS—there is no shortage of the key ingredient," Garlick adds.

"The issue is converting remaining oil in to commercial reality before the infrastructure [platforms and pipelines] expires." OE

Professor Ellen Williams, BP chief scientist.

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The first of these new innovations will take place at SPE Offshore Europe and are being organised with the generous assistance of GL Noble Denton, who have kindly provided the interviewees.

Meet our experts

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Confidence without complacency

SPE Offshore Europe's chairman Malcolm Webb gives his view on the outlook for the industry ahead of the event.

North Sea sector confidence and investment are riding high, but sustaining the record activity levels will be a challenge, says this year's SPE Offshore Europe chairman Malcolm Webb.

The chief executive of Oil & Gas UK has seen the industry through challenges to its safety regime, following the 2010 Macondo, Gulf of Mexico, disaster, and profitability, after successive tax increases by the UK Treasury.

So far, 2013, has been rewarding, he says. But, he warns ahead of September's SPE Offshore Europe in Aberdeen, the industry cannot be complacent.

Malcolm Webb

"2013 has so far been a rewarding year. The fear that offshore safety would be compromised by ill-conceived EU regulation has receded, replaced by reassurance that the directive now taking its place will preserve the UK's world-class regime.

"The industry is also responding strongly to recent changes in the UK tax regime by committing to record investment in the region.

"Investment in the UK continental

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shelf last year was in excess of £11 billion. This year it is forecast to rise even further, to at least £13 billion. No fewer than 30 new offshore oil and gas developments were approved in the last 12 months and 167 new production licenses were awarded in the latest licensing round.

"However, sustaining this intensity of activity will be a challenge. Despite record investment, production has fallen 30% in two years. Exploration has also faltered and production efficiency has declined from 80% to 60% in 10 years.

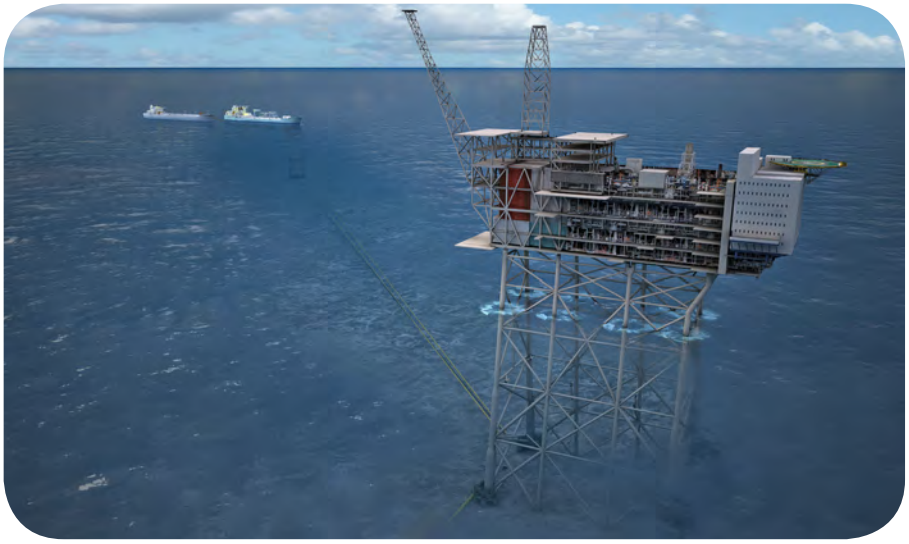
"The sector must fight to keep costs under control. Much focus is being given to maintaining aging infrastructure and delaying its decommissioning. Access to capital is still an issue for some small to medium-sized companies. Our industry also has a strong demand for skilled personnel to support its activities.

"Greater collaboration across industry and with governments will provide many of the solutions. Oil & Gas UK and its members are working with (sector skills training body) OPITO to build on companies' efforts to establish a collaborative industry strategy on skills.

"The industry is also developing a range of initiatives with both the UK and Scottish Governments to ensure access to skilled staff is maintained for the future health of the sector.

"Through Oil & Gas UK's Energizing the Nation's Future campaign, we are focusing on ways to better engage and explain the central role the industry plays through innovation, job creation and its economic contribution to the UK.

"The development and implementation of advanced technology will also be crucial in helping to improve exploration success, raise production efficiency and ultimately maximize the economic recovery of the UK oil and gas resource." OE



Statoil's UK North Sea Mariner heavy oil field development concept. The field, one a number of large developments driving North Sea spending, is due on stream in 2016.

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North Sea remains attractive

By Neil Golding, head of oil and gas, Energy Industries Council (EIC)

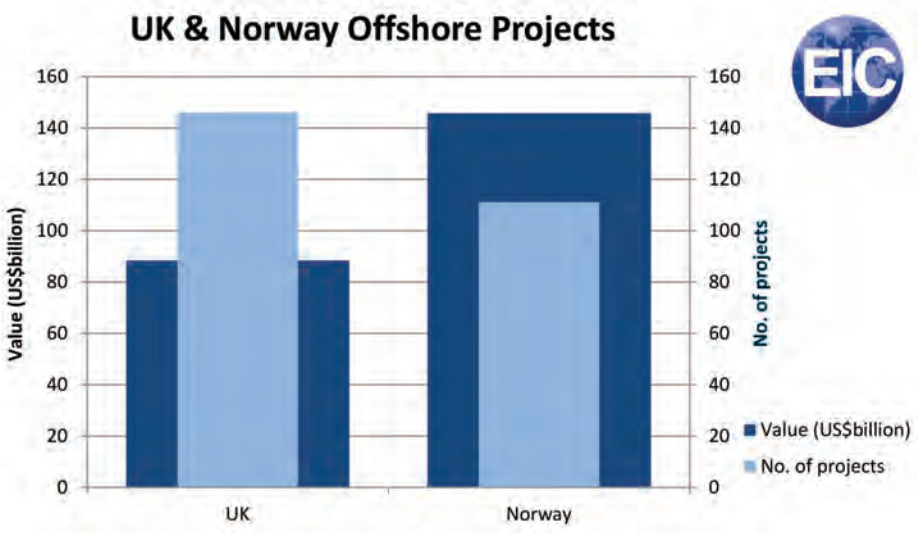
The North Sea is one of the most mature hydrocarbon provinces in the world, having relinquished more than 40 billion bbl and gas over the last four decades. Yet the development of advanced production technology, combined with a sustained high oil price, is fueling a resurgence of activity in the North Sea and beyond.

The UK's oil and gas industry in particular is attracting record investment. According to EICDataStream, there are 146 projects proposed or under development offshore UK, worth a total potential investment value of US$88.4 billion. The accompanying bar chart shows the UK figures compared to Norway, which has 111 active or future offshore oil and gas projects worth an estimated US$145.7 billion.

In 2012, the Treasury introduced a series of new field allowances covering West of Shetland developments, small fields and brownfield projects, which have paved the way for the exploitation of marginal developments or fields with declining resources, often through the utilization and expansion of existing infrastructure. These types of developments are often not on the radar of major international operators, opening the door to independent operators who, with current technologies such as subsea engineering and enhanced recovery at their disposal, can make a healthy profit from the development of these fields.

Indeed, independent operators such as EnQuest, Talisman and Endeavour were particularly successful at securing licenses in the UK's 27th oil and gas licensing round last year, with only a handful of the 167 licenses awarded going to the big players. The North Sea undoubtedly remains an attractive proposition for the oil and gas industry yet, at a time of declining field rates and complex and often remote reservoirs, it is now more important than ever to nurture technology and embrace innovative production methods. **OE**

Read more in the official Offshore Europe show daily, published by OE.



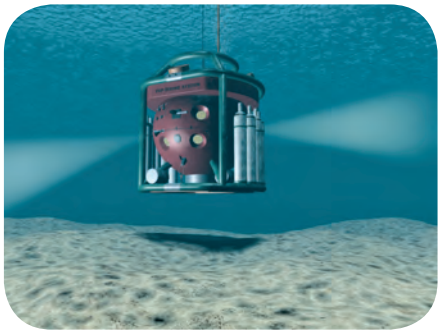
Solutions

Welding warrior

ESAB's new Warrior cutting tool is a heavy-duty, multi-process welding machine with wire feeder. It was developed for reliability, minimal downtime, and maximum productivity. The machine will perform MIG/MAG (metal inert gas/metal active gas), flux-cored wire, manual metal arc, and TIG welding tasks, as well as arc-gouging. It incorporates inverter technology for energy savings and high functionality, delivering up to 500 amps at 60% duty cycle. It welds 0.8-2.0mm flux-cored and solid wires, carbon arc-gouges with electrodes up to 10mm diameter and has a full range of MMA (manual metal arc) capabilities. The wire feeder has a high-torque, four-roll drive, offering superior feed, even with long MIG/MAG welding guns. Additional features include meters that can be read in sunlight, and accessible controls, which can be adjusted with a gloved hand. **www.esab.com**

New PDC cutter introduced

Smith Bits, a Schlumberger company, released the ONYX 360° rolling polycrystalline diamond compact (PDC) cutter. This technology enables a PDC cutter to rotate 360° while drilling, improving drillbit durability in abrasive formations and extending drillbit life and footage drilled per run. The rolling cutter uses its entire diamond edge to shear the formation as the bit rotates, distributing wear over its full circumference, and allowing the diamond edge to stay sharp longer—increasing penetration rates and extending drillbit.
www.slb.com/services/drilling/drill_bits.aspx



Under pressure

The TUP (transfer under pressure) Diving System, designed and built in-house by **N-Sea,** has undergone a refit and been converted to allow it be used as a mobile system, deployable from most DPII support vessels and platforms. The system will be online August 2013. The TUP Diving System is comprised of a three-men bell, launch and recovery system, triple lock decompression chamber, an air/mixed gas dive control and hyperbaric rescue craft.
www.n-sea.com

New drilling fluid system

Baker Hughes launched their MPRESS™ drilling fluid system, which allows operators to reduce stand pipe pressure and apply more horsepower to the bottomhole assembly and drill bit, increasing rates of penetration and decreasing non-productive time. Baker Hughes recently commercialized the MPRESS system to reduce viscosity in the drillstring, while optimizing viscosity in the annulus for more efficient cuttings transport.
www.bakerhughes.com

Increased seal offerings

Precision Polymer Engineering (PPE) broadened its range of advanced sealing. The new products are a range of spring seals—elastomer seals which incorporate a spring and are suitable for applications encountering high pressures, high temperatures or aggressive media and environments. The seals are available in Perlast and Endura materials, making them invaluable in extreme environments and applications such as downhole, wellhead, surface equipment and high pressure pipeline, and riser systems.
www.prepol.com

Altitude measurements

OceanTools Ltd. completed a redesign of their MA500 Precision Altimeter. DSP electronics combined with frequency swept CHIRP technology are housed in a hard anodized aluminium housing rated to 3000m as standard. The MA500 uses a new composite transducer array enabling altitude measurement with millimetric accuracy and resolution. It may be used in

a range of harsh environment altitude measuring applications such as assisting the safe navigation of subsea vehicles, deployment of structures to the seabed and the monitoring and measurement of sediment and ice.
www.oceantools.co.uk

Harsh environment lifejacket

VIKING Life-Saving Equipment introduced a new dual-approved thermal lifejacket with broad appeal for the offshore and commercial shipping industries operating in harsh, cold environments. The PV9720 has been tested and approved according to new stringent lifejacket performance standards as well as existing thermal requirements. The lifejacket is designed to protect against loss of body temperature with a built-in neoprene torso covering the core body, head and crotch area.
www.viking-life.com

Swellable packers introduced

TAM International Inc. established a new line of TAM FastSwell™ elastomers, adding to their extensive FREECAP® swellable packer product offering. TAM FastSwell™ provides a fast, controlled swell time at lower temperatures and high salinities. The product line was developed for challenging water-swell conditions in the US Permian Basin and Russia frac markets, but both water-swell and oil-swell elastomers are now available worldwide. The elastomers perform well for frac applications between 80°F and 120°F (32°C to 49°C).
www.tamintl.com

Emergency severance tool honored

SPEX Group, an Aberdeen-based provider of technology solutions and services to the oil and gas industry, won an excellence award for its success in the Technology Innovation category and was jointly named rising star at the Scottish regional judging of the PwC / HSBC Private Business Awards 2013. The Technology Innovation award recognized SPEX's development of the Emergency Severance Tool (EST), capable of cutting presently non-shearable components that are situated across the BOP stack.
www.spexservices.com

Turbine flow meter

AW-Lake Company launched its SABRE Turbine flowmeter for the subsea market. To keep the electronics dry and in a pressure-regulated environment, the meter was designed with integral, sealed electronics, allowing more valuable real estate in the subsea electronics module canister. This flowmeter is suitable for operating pressures up to 20,000 psi. Access to the electronics is through a special 6-pin connector made specifically for subsea use and has either an amplified pulse or 4-20mA output.
www.aw-lake.com

Marine vehicle design wins award

Autonomous Surface Vehicles (ASV) won the second phase of the recent SBRI competition to develop a long endurance marine unmanned surface vehicle (LEMUSV). ASV will undertake the detailed production design, build, commissioning and sea trials of a fully operational, open ocean going C-Enduro 4 vessel. The vehicle design will utilize technologies from the consortium and be designed specifically to be capable of being deployed at sea for up to three months in all weather conditions and sea states.
www.asvglobal.com

Activity

Halliburton opened its new Technology Center at the Federal University of Rio de Janeiro (UFRJ) Technology Park, located at Ilha do Fundão, Rio de Janeiro, Brazil. The center provides the setting for collaboration as the company works with the country's leading universities and customer research groups to establish a global center of expertise for deepwater and mature fields, and includes specialized laboratories, a collaboration room, a testing area, and conference and training rooms.

The Imaging Systems Group Inc. (iSys), developer and manufacturer of direct thermal, inkjet and digital printers & plotters for the oil and gas industry, is opening a new office location in Houston. The new facility will be used for training purposes, and allows for a larger demo room to house eleven of their printers for the oil & gas and digital label industries.

AnTech Ltd. secured an investment from **Saudi Aramco Energy Ventures (SAEV)** and London-based **Calculus Capital**. The funding is being used to launch AnTech's new DCTD service capability so that it can use its bespoke systems to deliver cost-effective directional drilling solutions to the oil and gas industry.

Reservoir Group affiliate, **Omega Well Monitoring Canada (OWMC)**, acquired **Planet Services Inc.** This acquisition furthers OWMC's plans to transition from a sales-based company, to a provider of installation and servicing. Planet Services has supported Omega becoming the principal installation provider covering installations in Canada, parts of the US and some international operations in China, Iraq, Nigeria, and Tunisia.

Intervention & Coiled Tubing Association (ICoTA) is requesting nominations for its European Chapter Innovation Award, recognizing the application of technical innovation in the area of well intervention. Entrants will be judged by the ICoTA European Chapter Committee. Deadline is September 23, 2013, and finalists will be required to deliver a short presentation on October 31 at the Marcliffe Hotel, Aberdeen. The winner will be announced at SPE ICoTA European Well Intervention Conference on November 13 and 14, 2013.

GE Oil & Gas acquired **Lufkin Industries** in a deal valued at US$3.3billion. Lufkin manufactures and services artificial lift equipment through more than 110 service centers and nine manufacturing facilities. GE says automation is an integral part of Lufkin's approach to artificial lift optimization and its product line contains the building blocks that will help to develop an artificial lift "industrial internet" through a connected network of technology, data and experts.

Xodus Group acquired Dubai-based **Prime Energy**, as part of an expansion drive in the eastern hemisphere. It is the first acquisition Xodus has

made in the Middle East following the launch of its Dubai operations in 2012. Prime Energy's team will form part of Xodus' subsidiary based in Dubai, Xodus DMCC, which will be renamed Xodus-Prime DMCC.

Devan International Ltd., a subsidiary of **Keppel Corporation Ltd. (KCL)**, acquired a 20% shareholding interest in the enlarged share capital of **KrisEnergy Ltd**. KrisEnergy is currently an associated company of KCL. In connection with the acquisition, Devan was granted a call option to acquire additional ordinary shares in the company.

Schlumberger acquired **Gushor Inc.**, a Canadian-based petroleum geochemistry and fluid analysis company that provides production and exploration solutions in the heavy oil and oil sand (HOOS) industry. Formed in 2006, Gushor specializes in the integration of geology, fluid properties, petroleum geochemistry and reservoir engineering information. "The addition of Gushor complements our leading fluids and rocks technology portfolio with geochemical and fluid property analysis capabilities," said Sameh Hanna, president, testing services, Schlumberger.

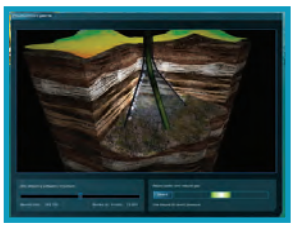
COOPER Valves, manufacturer of exotic and nickel alloy industrial valves, partnered with **Industrial Logistics/LAVISA**, a PVF supply and distribution company, in efforts to expand its exposure in Mexico, Central America, and South America. The company will be conducting training sessions with Industrial Logistics/LAVISA staff at their Houston and Mexico offices over the coming months. This training will sustain the relationship as well as ensure Industrial Logistics/LAVISA has the knowledge they need to grow COOPER Valves in the Latin American market.

GE Oil and Gas will establish its new global headquarters in London, which it expects to be operational by January 2014. Florence will remain the global headquarters for GE Oil & Gas' Turbomachinery Products and Services. "London was selected as the new headquarters location given its position as a leading international business and travel hub. From this location, a team of leaders from our global support functions will be able to more efficiently reach and serve our colleagues and businesses globally," said Dan Heintzelman, president and CEO of GE Oil & Gas. The new global headquarters will support the business and 43,000 employees working in more than 100 countries.

Vallourec inaugurated a new research center in Rio de Janeiro, due to open in October. The center, located next to Petrobras' CENPES, will focus on Vallourec's pre-salt activities, with the support from Vallourec's center in Belo Horizonte, which was recently expanded. The Rio center will benefit from synergies with the Federal Universities of Rio de Janeiro and Minas Gerais among others, in areas such as the environment, robotics, and energy use.

Spotlight

By Anthresia McWashington



The *Quest for Oil* goes online

Maersk Oil launched the web-only video game *Quest for Oil* early this summer with the aim of making the oil and gas industry more accessible. *OE* discusses the strategy behind the game with CEO Jakob Thomasen.

Maersk Oil launches industry video game *Quest for Oil.*

Maersk Oil launched the video game, *Quest for Oil*, to give people—inside and outside of the business—a better perspective about what occurs within the exploration realm of the industry. *Quest for Oil* allows players to use their strategic and practical skills to retrieve oil virtually from deep waters off Qatar and in the North Sea. The game provides a detailed look at the exploration process, and allows users to make operational decisions.

Maersk Oil CEO, Jakob Thomasen, says that without understanding the process of retrieving and producing oil, having these natural resources often gets taken for granted.

"Not many people understand what it takes to find and produce oil and gas," Thomasen says. "The world's need for oil and gas is leading exploration into ever deeper waters and ventures demanding precision and cutting-edge technology."

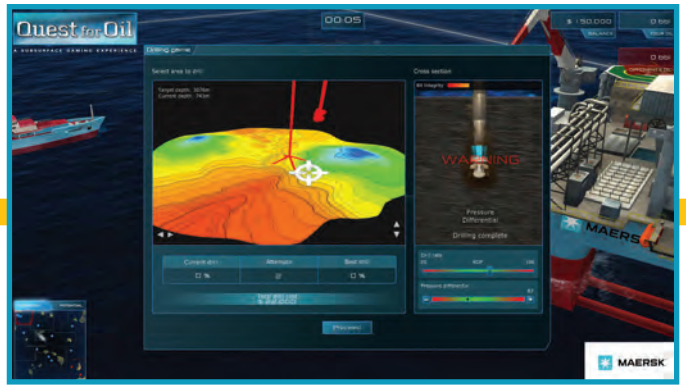
Quest for Oil became a fresh, innovative method for Maersk Oil to spread the word about the industry. Thomasen says the game engages audience members with opportunities to get involved in the world of exploration and production.

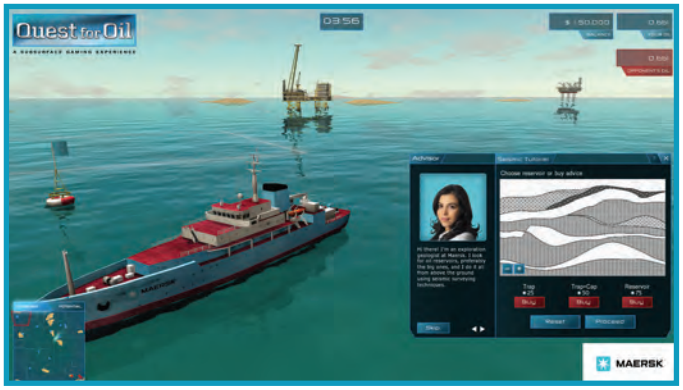
A team of two from Maersk, along with three different external agencies and their team members, came together to execute the US $400,000 project, which took eight months to finalize from the start of production.

"Our goal with *Quest for Oil* has been to invite everyone in to our 'homebase' and inform, educate, inspire, engage and have a dialogue," he says. "We hope that a game like this can create some awareness about the industry and how exciting it is to work here, that we have jobs in the future, and that you can have the world as your playground."

The game teaches players how to read the earth's layers—and determine how to detect and find oil reservoirs, and how to determine if you're about to strike a dry well. Seismic analysis, reservoir identification, placing and drilling wells, and setting up and optimizing production are all challenges that players will face while immersed in the game.

Thomasen says the company plans to integrate the game into Maersk Oil and Maersk Drilling as part of an introduction package, as





Quest for Oil teaches players how to read the earth's layers, how to detect where to find oil reservoirs, and how to determine if you're about to strike a dry well.

Entrance and Egress

US Bureau of Safety and Environmental Enforcement (BSEE) Director **James A. Watson** will step down to join maritime class society ABS as its president and chief operating officer (COO) of the Americas Division, effective September 2013.

Chevron North Sea Ltd. appointed **Craig May** to managing director of Chevron Upstream Europe, based in Aberdeen.

Mario Azar was appointed to CEO of the solutions business unit in the oil & gas division of Siemens' Energy Sector, effective last month.

George Molski, president of Fortis Energy Services, Inc. will transition from his role as president to business consultant.

Simon Lowth, current CFO and executive director of AstraZeneca PLC, will leave the company for BG Group to hold the same respective positions, effective November 2013.

Pete Jones leaves Marathon Oil to become managing director TAQA's UK oil and gas business.

The OPI International Group appointed **George Amaral** to MDC (Malembo Development Centre) as country manager, effective last month.

Dr. Michael Hession joins InterOil as the company's new CEO, effective July 2013.

well as offering the game during training sessions and courses at the Maersk training center. Furthermore, the company is working on an educational package to be distributed to high schools in Denmark for educational purposes on the industry.

He also said that Maersk has been researching ways to recruit more women to industry, and that the game has already sparked some interest in a few women who've submitted applications to the company.

"We have been thinking about how to attract more women to the industry, but women have not been a specific target group itself (for the game). We're focusing on attracting more women to the industry in general. We've already received a couple of applications from women who would like to work here, after playing *Quest for Oil*," he says.

As knowledge and interest in the game expands, Thomasen says Maersk hopes to add *Quest for Oil* as another method of interaction with consumers. For now, the company has been responding to feedback about the game through social media and email.

"We will now monitor the feedback and see how we can integrate it in our business, no doubt that this type of media for communication and dialogue with our audience is in the future," Thomasen says. "We are tracking our social media channels and responding directly to emails via questforoil.maersk.com." OE

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Advertiser Index

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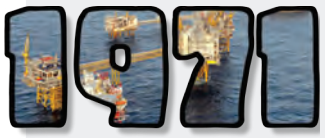
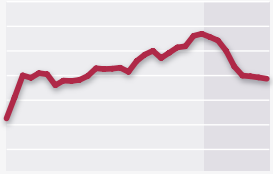
Numerology

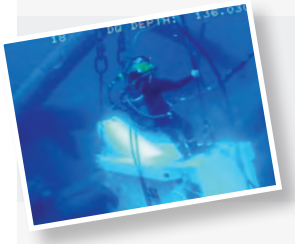
6 Offshore blocks were awarded during Open Round Colombia 2012.
▶ See Latin America, page 72.



Production from the Ekofisk oil field in the Norwegian North Sea begins.
(Source: Norwegian Petroleum Directorate)

23.6% Decline in production that Mexico experienced in one decade.
▶ See Analysis, page 21.





150 Structures are to be removed from the Gulf of Mexico by yearend 2013. ▶ See Decomissioning, page 26.

13,000 Flow rate, in b/d, achieved at the St. Malo prospect in the Gulf of Mexico. *(Source: Chevron)*

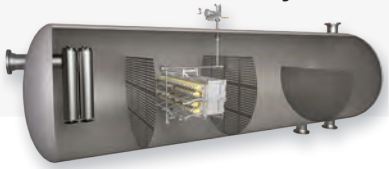
20yrs The life span of the Perdido project. *(Source: Shell)*

2017

The year Asia is forecasted to have the highest demand for heavy lift vessels. ▶ See EPIC-Lifting, page 52.

10,411ft The world record set by Transocean's *Dhirubhai Deepwater KG1* drillship for deepest water depth.
▶ See Global Briefs, page 14.

50% Of the world's remaining oil reserves are either heavy or extra-heavy quality.
▶ See Production, page 58.



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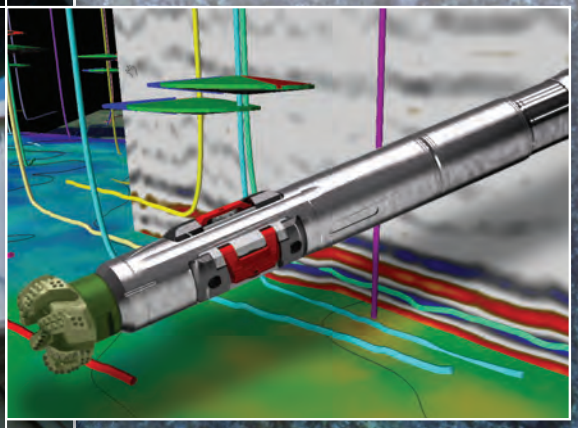

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